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EXHIBITS (CONTINUED)

ORIGINAL

In The
SUPREME COURT OF OHIO

State of Ohio, ***ex rel.*** **Industrial Energy Users-Ohio,**	:	
	:	Case No. 12-1494
Relator,	:	
	:	**ORIGINAL ACTION IN PROHIBITION AND MANDAMUS**
v.	:	
The Public Utilities Commission of Ohio, ***et al.***	:	
Respondents.	:	

MOTION TO DISMISS
SUBMITTED ON BEHALF OF RESPONDENTS,
THE PUBLIC UTILITIES COMMISSION OF OHIO, *ET AL.*

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Pursuant to S. Ct. Prac. R. 10.2 and 10.5 and Ohio Civ. R. 12(B)(1) and (6), The Public Utilities Commission of Ohio, *et al.*, moves the Court to dismiss the Complaint for Writs of Prohibition and Mandamus that Relator Industrial Energy Users-Ohio filed on August 31, 2012. The grounds for this motion are set forth in the accompanying Memorandum in Support.

Respectfully submitted,

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MEMORANDUM IN SUPPORT

INTRODUCTION

Relator objects to the Commission setting a rate to be paid by Competitive Retail Electric Service Providers (CRES) for capacity and asks this Court to grant it writs of Prohibition and Mandamus. The simple fact is that these rates are in effect. The tariffs imposing this charge are in place and CRES providers are paying them. A writ of Prohibition will not issue to reverse an action already taken and this action has been taken. Prohibition is not available. Further the Relator has a complete remedy at law, specifically a statutory appeal of right and the statutory ability to seek a stay of the Commission order. As there is a complete remedy at law, Mandamus is not available. Relator has no case and the Complaint should be dismissed.

FACTUAL BACKGROUND

The factual background is described in the pleadings of Relator and will not be repeated here save to say that the proceedings below have been remarkably complicated as will be seen if appeals are taken after the Commission issues final orders in 10-2929-EL-UNC (*Capacity Pricing case*) and 11-346-EL-SSO, et al. (*ESP II case*).

ARGUMENT

I. Relator is not entitled to a writ of prohibition.

The Court must dismiss an original action if it appears from the pleadings that the relator can prove no set of facts that would permit issuance of the writ. *State ex rel. Lanham v. Ohio Adult Parole Auth.*, 80 Ohio St.3d 425, 426, 687 N.E.2d 283 (1997). As the Court well knows, a writ of prohibition is an "extraordinary remedy which is customarily granted with caution and restraint." *State ex rel. Henry v. Britt*, 67 Ohio St.2d 71, 73, 424 N.E.2d 297 (1981). Because of its extraordinary nature, the Court has held that it will not grant a writ of prohibition "routinely or easily." *State ex rel. Barclays Bank PLC v. Hamilton Cty. Court of Common Pleas*, 74 Ohio St.3d 536, 540, 660 N.E.2d 458 (1996). The right to prohibition "must be clear, and in a doubtful or borderline case its issuance should be refused." *State ex rel. Merion v. Court of Common Pleas of Tuscarawas Cty.*, 136 Ohio St. 273, 277, 28 N.E.2d 641 (1940).

To be entitled to a writ of prohibition, Relator must prove all three of the following elements, which require Relator to show that "(1) respondents are about to exercise judicial or quasi-judicial power, (2) the exercise of that power is unauthorized by law, and (3) denying the writ will result in injury for which no other adequate remedy exists in the ordinary course of law." *State ex rel. Youngstown v. Mahoning Cty. Bd. of Elections*, 72 Ohio St.3d 69, 71, 647 N.E.2d 769 (1995) (internal citations omitted). Relator, who bears the burden of proof on each necessary element, simply cannot establish these elements. Its request for an extraordinary writ must be refused.

A. Relator cannot demonstrate that the Commission is "*about to* exercise *judicial or quasi-judicial power.*"

Relator is too late. The actions that Relator seeks to prohibit have already been taken. The tariffs to which Relator objects are already in place. Prohibition will not lie to undo a "fait accompli" or prohibit a decision or order that has already been made. *E.g., State ex rel. Ohio Stove Co. v. Coffinberry,* 149 Ohio St. 400, 79 N.E.2d 123 (1948), syllabus. Further, the Commission is exercising legislative not judicial or quasi-judicial power.

1. The Tariffs are already in effect.

Relator is not challenging actions that the Commission is "about to" take. Instead, Relator attacks orders that the Commission has already issued. It has long been established that writs of prohibition are not meant for reviewing the regularity of acts already performed. As this Court held:

> A writ of prohibition may be awarded only to prevent the unlawful usurpation of jurisdiction and does not lie to prevent the enforcement of a claimed erroneous judgment previously entered or the administrative acts following the rendition of a judgment *** . It may be invoked only to prevent proceeding in a matter in which there is an absence of jurisdiction and not to review the regularity of an act already performed.

(Emphasis added.) *State ex rel. Moss v. Clair*, 148 Ohio St. 642, 76 N.E.2d 883 (1947), paragraph one of the syllabus (internal citations omitted). *See also Coffinberry*, 149 Ohio St. 400.

Relator asks this Court to undo the July 2, 2012 and August 8, 2012 Orders that the Commission already handed down in the *Capacity Pricing* and *ESP II* cases respectively. For example, Relator asks this Court to "prohibit the Commission from inventing and applying a Cost-Based ratemaking methodology to increase significantly and uniquely [Ohio Power's] compensation for generation capacity service available to CRES providers serving retail customers located in [Ohio Power's] service area." Complaint at 23. But the Commission's *Capacity Pricing* Order *already* asserted jurisdiction under the Revised Code to establish a cost-based state compensation mechanism (SCM). *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company*, Case No. 10-2929-EL-UNC (*Capacity Pricing*) (Opinion and Order at 22) (July 2, 2012) ("We conclude that the state compensation mechanism for [Ohio Power] should be based on the Company's costs."), Relator's App. at 222.[1] Relator also asks this Court to "prohibit the Commission from authorizing [Ohio Power] to collect the above-market portion of such increased compensation on shopping and non-shopping customers through non-bypassable charges now and later. Complaint at 23. But the *ESP II* Order *already* authorized Ohio Power to collect this compensation. *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case Nos. 11-346-EL-SSO, *et al.* (*ESP II*) (Opinion and Order at 51) (August 8, 2012), Relator's App. at 319. These are just two examples of Relator's attempt to undo what the

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1 References to Relator's appendix, filed in conjunction with its Complaint for Writs of Prohibition and Mandamus, are denoted "Relator's App. at ____;" references to Respondents appendix attached hereto are denoted "App. at ___."

Commission has already done. R.C. 4903.15 makes Commission orders effective immediately. There is no further delay in the effectiveness of these orders; tariffs are filed and rates have been implemented.

The Commission already acted in issuing the *Capacity Pricing* and *ESP II* Orders. Those orders, as a matter of law, are immediately effective upon their issuance. R.C. 4903.15, App. at 2. Because prohibition is a preventive, not a corrective remedy, it cannot be used to circumvent the standard review and appellate process. *See State ex rel. Celebrezze v. Butler Cty. Common Pleas Court*, 50 Ohio St.2d 188, 190, 398 N.E.2d 777 (1979). A writ or prohibition "cannot be used to review the regularity of an act already performed." *Id.* Relator's Complaint must be dismissed.

2. Ratemaking is a Legislative Function.

Neither the *Capacity Pricing* Order nor the *ESP II* Order involved the exercise of judicial or quasi-judicial authority. Both orders were issued pursuant to *ratemaking* authority.

Ratemaking is a "legislative function," not a quasi-judicial one:

> At common law, a utility had the same right as other businesses to set the rate for its services. Its customers had no substantive right to a fixed rate, and thus had no procedural rights in the ratemaking process. With the advent of regulation, ratemaking became solely a legislative function and, absent express statutory provision, ratepayers had no right to participate in that process through the ballot box.

Consumers' Counsel v. Pub. Util. Comm., 70 Ohio St.3d 244, 249, 1994-Ohio-469, 638 N.E.2d 550 (emphasis added). *See also Dayton Power & Light Co. v. Pub. Util. Comm.*, 4 Ohio St.3d 91, 98-99, 447 N.E.2d 733 (1983) (referring to the "legislative power to fix utility rates" and referring to the rate-setting agency as the legislative body's "administrative surrogate").[2]

Because the Commission exercised legislative authority, prohibition is unavailable. Relator's Complaint should be dismissed.

B. Relator has not established that the Commission lacked jurisdiction.

Unless the Court determines that Relator has met its heavy burden of showing that the Commission patently and unambiguously lacks jurisdiction over the *Capacity Pricing* case and the *ESP II* case, Relator's Complaint should be dismissed. Relator's Complaint pleads no such claim.

Neither can Relator meet its burden. The Commission has wide-ranging authority over public utilities in Ohio that this Court has described as "broad and complete." *Kazmaier Supermarket ,Inc. v. Toledo Edison Co.*, 61 Ohio St.3d 147, 150-51, 573 N.E.2d 655 (1991).

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2 The United States Supreme Court also has consistently held that ratemaking is legislative in nature. *See Permian Basin Area Rate Cases*, 390 U.S. 747, 776, 88 S. Ct. 1344 (1968) (noting that the view of administrative ratemaking uniformly taken by the Court is that the "legislative discretion implied in the ratemaking power necessarily extends to the entire legislative process, embracing the method used in reaching the legislative determination as well as that determination itself"); *New Orleans Pub. Serv. Inc. v. Council of New Orleans*, 491 U.S. 350, 371, 109 S. Ct. 2506 (1989) (holding that an action brought by a utility for a rate increase was legislative in nature); *FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 599, 609, 62 S. Ct. 736 (1942) (concurring opinion stating that ratemaking is "legislative price fixing" and referring to the "legislative power to fix utility rates").

> R.C. Title 49 sets forth a detailed statutory framework for the regulation of utility service and the fixation of rates charged by public utilities to their customers. As part of that scheme, the legislature created the Public Utilities Commission and empowered it with broad authority to administer and enforce the provisions of Title 49.

Id. at 150. Indeed, "there is perhaps no field of business subject to greater statutory and governmental control than that of the public utility." *Id.* The Commission thus has "exclusive jurisdiction over various matters involving public utilities, such as rates and charges, classifications, and service." *State ex rel. Illum. Co. v. Cuyahoga Cty. Court of Common Pleas*, 97 Ohio St.3d 69, 2002-Ohio-5312, 776 N.E.2d 92, ¶ 18, *quoting State ex rel. Cleveland Elec. Illum. Co. v. Cuyahoga Cty. Court of Common Pleas*, 88 Ohio St.3d 447, 450, 727 N.E.2d 900 (2000); *accord State ex rel. Columbus Southern Power Co. v. Fais*, 117 Ohio St.3d 340, 2008-Ohio-849, 884 N.E.2d 1, ¶ 19. The complaint should be dismissed.

1. Relator has not shown that the Commission lacked authority in the *Capacity Pricing* case.

Relator claims that the Commission lacked jurisdiction in the *Capacity Pricing* case to establish a cost-based capacity charge because capacity is a competitive and unregulated "retail electric service" within the meaning of R.C. 4928.01(A)(27). But, the Commission found that it was not a retail service. In the *Capacity Pricing* Order, the Commission considered the statutory definition of "retail electric service" set forth in R.C. 4928.01(A)(27) to reach the obvious conclusion that *wholesale* capacity service is not a "retail electric service." *Capacity Pricing* Order at 13, Relator's App. at 213. This

Court gives considerable weight to the Commission's expertise in interpreting a law where "highly specialized issues" are involved and where agency expertise would, therefore, be of assistance in discerning the presumed intent of the General Assembly. *Consumers' Counsel v. Pub. Util. Comm.*, 58 Ohio St.2d 108, 388 N.E.2d 1370 (1979).

The Commission here correctly concluded that capacity service is not provided directly to retail customers, but rather is a wholesale transaction between Ohio Power and Competitive Retail Electric Suppliers (CRES) providers operating in Ohio Power's service territory. *Capacity Pricing* Order at 13, Relator's App. at 222. As such, the Commission concluded that it was authorized to set a cost-based rate for capacity pursuant to the Reliability Assurance Agreement (RAA) – which, as noted, is part of a Federal Energy Regulatory Commission (FERC) approved tariff – and this Commission's general supervisory authority over public utilities under R.C. Chapter 4905. The Commission asserted its jurisdiction after the FERC action deferring to the State Compensation Mechanism in the December 2010 decision that started this Commission investigation.[3] Relator argues that the Commission lacked authority because it was required to conduct a traditional base rate case under R.C. Chapter 4909. Relator is wrong. The Commission indicated that it was exercising authority to establish a state compensation mechanism under R.C. 4905.04, 4905.05, and 4905.06, as well as under Chapters 4905 and 4909 and the FERC-approved RAA. *Capacity Pricing* Order at 12-14, 22, Realtor's App. at 212-214, 222. Even if Relator was correct, a procedural error of this sort is exactly what the

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[3] FERC Docket No. ERll-2183

normal appeal process is intended to resolve. It cannot form the basis for a writ of Prohibition.

As referenced above, Relator's theory that the Commission lacked jurisdiction to establish cost-based pricing for capacity service also assumes that capacity service is a "competitive" retail electric service. Memorandum in Support at 56 (once declared competitive, the capacity service is beyond the scope of the provisions contained in R.C. Chapter 4909). This conflicts with the Commission's express findings and the uncontested facts established in the evidentiary record below. Relator even defeats its own proposition by explicitly acknowledging that some generation services can be priced based on cost. *Id.* at 66.

Commissioner Roberto's concurring decision noted:

> I agree with the majority that the Commission is empowered pursuant to its general supervisory authority found in Sections 4905.04, 4905.05, and 4905.06, Revised Code to establish an appropriate rate for the Fixed Resource Requirement service. I also agree that pursuant to regulatory authority under Chapter 4905, Revised Code, as well as Chapter 4909, Revised Code a cost-based compensation method is necessary and appropriate. *Additionally, I find that because the Fixed Resource Requirement is a noncompetitive retail electric service, the Commission must establish the appropriate rate based upon traditional cost of service principles.*

Capacity Pricing (Concurring and Dissenting Opinion of Commissioner Cheryl L. Roberto at 4) (July 2, 2012), Relator's App. at 245. Commissioner Roberto's conclusion that capacity service should be considered non-competitive was based on the simple factual observation that "[n]o other entity may provide this service during the term of the current [Ohio Power] Fixed Resource Requirement Capacity Plan [through May 2015]."

Id. at 2, Relator's App. at 243. The underlying facts were not contested by parties below. Ohio Power had to sell and CRES providers had to buy capacity. Therefore capacity cannot be a competitive service.

In the alternative, IEU claims that the ratemaking formula applies and was not followed closely enough. This is an issue that can be pursued on appeal and is not a proper basis for a writ of Prohibition.

Even if Ohio procedural and substantive ratemaking requirements were strictly applicable, which standards to apply would be at issue. The statute, R.C. 4909.18, provides two mechanisms, a standard rate case and a "first filing" of rates for a service not previously addressed in a PUCO-approved tariff. R.C. 4909.18, App. at 3-4. The latter does not require a hearing, although extensive hearings were conducted. *See, e.g., Consumers' Counsel v. Pub. Util. Comm.*, 111 Ohio St.3d 300, 2006-Ohio-5789, 856 N.E.2d 213, ¶ 16-18. Likewise a "first filing" does not require a use of the ratemaking formula. In sum, even if the Relator were correct, it has only raised an arguable matter to which the appeals process should apply.

2. The FERC, through the RAA, has deferred to the Commission's determination of the pricing of capacity service.

As the Commission specifically found in the *Capacity Pricing* decision, Ohio Power's capacity service is a wholesale service. FERC would normally have jurisdiction over wholesale electric service, but FERC has deferred to the Commission, through the RAA, which acknowledges the authority of a state regulatory jurisdiction (such as the

Commission) to establish a SCM in connection with the provision of wholesale capacity service. In conjunction with this deferral by FERC under the RAA, the Commission can exercise jurisdiction to establish a SCM pursuant to its broad regulatory powers under Chapters 4905 and 4909 of the Revised Code.

In sum, the Commission acted within the authority deferred to it by the FERC, as a state regulatory jurisdiction, to establish a wholesale capacity rate under state law. If the Relator has issues with this it should present those issues to the Court through an appeal and certainly not in the context of a writ of prohibition.

3. Relator has not shown that the Commission lacked authority in the *ESP II* case.

Relator asserts that the Commission was without authority to impose a non-bypassable charge through a retail stability rider or "RSR" as part of Ohio Power's ESP. The statute says otherwise. R.C. 4923.143(B)(2)(d) authorizes the Commission to include within an ESP the following:

> *Terms, conditions, or charges* relating to [1] limitations on customer shopping for retail electric generation service, [2] bypassability, [3] standby, back-up, or supplemental power service, [4] default service, [5] carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, *as would have the effect of stabilizing or providing certainty regarding retail electric service*;

R.C. 4928.143(B)(2)(d), App. at 6 (emphasis and numbered brackets added.) Thus an ESP may include terms, conditions, or charges relating to limitations on customer shopping for retail electric generation and bypassability that would have the effect of stabilizing or providing certainty over retail electric service. This is the purpose of the

RSR. The authority clearly exists and an appeal in the normal course will answer the question of whether the Commission used that power reasonably. The complaint should be dismissed.

C. Relator has adequate remedies at law.

Finally, Relator is not entitled to a writ of prohibition because it has adequate legal remedies. "Prohibition will not lie to prevent an anticipated erroneous judgment." *State ex el. Jones v. Suster*, 84 Ohio St.3d 70, 74, 701 N.E.2d 1002 (1998). Prohibition is not a substitute for an appeal. *State ex rel. Ragozine v. Shaker*, 96 Ohio St.2d 201, 2002-Ohio-3992, 772 N.E.2d 1192, ¶ 7. In the absence of a patent and unambiguous lack of jurisdiction, which the complaint does not plead, Relator is required to pursue its available legal remedies.

The General Assembly has established a comprehensive scheme for reviewing Commission orders. Relator should use it and indeed it has taken the first step by filing for rehearing. Any party that has entered an appearance in a Commission proceeding may apply for rehearing "in respect to any matters determined in the proceeding." R.C. 4903.10, App. at 1-2. In response, the Commission may abrogate, modify, or affirm its order. *Id.* at R.C. 4903.10(B), App. at 1-2. Here, Relator is participating in the rehearing process, having already filed applications seeking rehearing of both orders that it is challenging in this action. After the rehearing process is completed, Relator may then file an appeal of right to this Court. R.C. 4903.11, App. at 2. During the pendency of the appeal, Relator may also seek a stay of the Commission's orders. R.C. 4903.16, App. at

3. And, on review, this Court may reverse, vacate, modify, or affirm the Commission's orders. R.C. 4903.13, App. at 2.

The fact that refunds are unavailable in the event that Relator ultimately prevails does not render its legal remedies inadequate. This Court concluded that the unavailability of refunds is mitigated by the ability of an aggrieved party to seek a stay under R.C. 4903.16. *In re Columbus Southern Power Co.*, 128 Ohio St.3d 512, 2011-Ohio-2011 at ¶ 17. While the statute requires the party seeking a stay to post a bond, this Court cannot relieve a party from the bond requirement that the General Assembly has imposed by statute. "Unquestionably, it is the prerogative of the General Assembly to establish the bounds and rules of public-utility regulation." *Id.* at ¶ 19.

Rather than challenging the Commission's exercise of jurisdiction over the subject matter, Relator is challenging the way in which the Commission exercised its authority. This, however, is not the purpose of a writ of prohibition. The Court has stated that "[p]rohibition does not lie to prevent a merely erroneous decision by the court." *State ex rel. Enyart v. O'Neill*, 71 Ohio St.3d 655, 656, 646 N.E.2d 1110, 1112 (1995). The Court in *Enyart* concluded that, because the respondent judge had jurisdiction to rule on a motion for relief from judgment, "the fact that she may have exercised that jurisdiction erroneously does not give rise to extraordinary relief by prohibition." *Id.*; *see also State ex rel. CNG Financial Corp. v. Nadel*, 111 Ohio St.3d 149, 153, 855 N.E.2d 473, 478 (2006) (errors in exercise of jurisdiction are not remediable by writ of prohibition).

Under the exhaustion of remedies doctrine, courts will generally permit the administrative process to run its course before granting judicial relief. The Court has noted the "long settled rule of judicial administration that no one is entitled to judicial relief for a supposed or threatened injury until the prescribed administrative remedy has been exhausted." *Jones v. Chagrin Falls*, 77 Ohio St.3d 456, 462, 674 N.E.2d 1388, 1392 (1997), quoting *Myers v. Bethlehem Shipbuilding Corp.*, 303 U.S. 41, 50-51 (1938). As explained in another decision, "[t]he purpose of the doctrine of exhaustion of administrative remedies is to prevent premature interference with the administrative processes." *Basic Distrib. Corp. v. Ohio Dept. of Taxation*, 94 Ohio St.3d 287, 290, 762 N.E.2d 979, 984 (2002). Consistent with this principle, the Court should permit the Commission to address the pending applications for rehearing, including Relator's applications, before granting extraordinary judicial relief to Relator here.

II. Relator is not entitled to a writ of mandamus.

Relator's complaint for mandamus should be dismissed for many of the same reasons that apply to the prohibition question. Mandamus is an extraordinary remedy, and should be granted only under exceptional circumstances. *State ex rel. Crabtree v. Franklin Cty. Bd. of Health*, 77 Ohio St.3d 247, 249, 673 N.E.2d 1281 (1997). The elements of a writ of mandamus are: (1) the respondent has a clear legal duty to perform the act requested; (2) the relator has a clear legal right to the relief requested, and (3) the relator has no plain and adequate remedy in the ordinary course of the law. *State ex rel. Bennett v. Bds. of Edn*, 56 Ohio St.3d 1, 2-3, 564 N.E.2d 407 (1990).

Relator identifies no legal duty and, as discussed previously, no clear legal right to the relief requested. Relator has not pleaded nor demonstrated that the Commission patently and unambiguously lacks jurisdiction. Although Relator asserts the Commission "patently and unambiguously" lacks jurisdiction in the memorandum in support of its complaint, this does not cure the deficiency of pleading it as an allegation in Relator's complaint. This is yet another reason why having an adequate remedy at law is material to the Court's consideration of Respondents motion to dismiss.

Moreover, Relator has an adequate remedy at law. *See State ex rel. Hunter v. Certain Judges of the Akron Mun. Court*, 71 Ohio St.3d 45, 46, 641 N.E.2d 722 (1994). *See, e.g., State ex rel. Gillivan v. Ohio Bd. of Tax Appeals*, 70 Ohio St.3d 196, 200, 638 N.E.2d 74 (1994) ("Where a constitutional process of appeal has been legislatively provided, the sole fact that pursuing such process would encompass more delay and inconvenience than seeking a writ of mandamus is insufficient to prevent the process from constituting a plain and adequate remedy in the ordinary course of the law."); *State ex rel. Banc One Corp. v. Walker*, 86 Ohio St.3d 169, 173-74, 712 N.E.2d 742 (1999). An extraordinary writ is not a substitute for appeal and cannot be used to circumvent the statutory process set forth in R.C. Chapter 4903.

Relator also failed to state a claim for a writ of mandamus in this cause of action based on its pleading and prayer to have this Court compel the PUCO to *restore* the lower rate of RPM-Based Pricing as the state compensation mechanism and capacity rate for AEP-Ohio (see ¶ 18 of Complaint and prayer 5 for relief at the end of the Complaint). Relator concedes, through its own pleading and request for relief, that Respondents have jurisdiction to authorize a capacity rate and state compensation mechanism for AEP-Ohio. Relator contests only the method used (Cost-Based instead of RPM-Based) and resulting rate ($188.88/MW-day for 2012-2015 instead of $20.01/MW-day for 2012/2013 and $33.71/MW-day for 2013/2014 and $153.89/MW-day for 2014/2015) and not the PUCO's authority and jurisdiction to establish and implement a capacity rate or state compensation mechanism.

Relator further undermines its claim that the PUCO lacked jurisdiction to act in the AEP-Ohio Capacity Case and ESP II Case to establish a capacity rate or state compensation mechanism with its allegation that "...to the extent that the Commission did have jurisdiction to set prices for generation capacity service using a Cost-Based ratemaking methodology the Commission had totally failed to follow the ratemaking process or formula that Ohio law mandates...." (See ¶ 26 and similar claims in ¶ 36 (d) of Complaint, and prayer 3 for relief of Relator's complaint). Relator claims error in procedure, which is an appellate issue that an appeal can remedy; not an issue that requires an original action and an extraordinary remedy.

CONCLUSION

Relator did not receive a favorable decision from the Commission. Dissatisfaction is not a basis for either a writ of Prohibition or Mandamus. Relator, however, has failed to meet its heavy burden of proving that the Commission was without authority to act, let alone that that the Commission patently and unambiguously lacked jurisdiction. At most Relator has laid out arguments that should be dealt with through the normal course of appeal. The Court should dismiss the case and allow the appeals to proceed in the normal fashion.

Respectfully submitted,

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PROOF OF SERVICE

I hereby certify that a true copy of the foregoing Motion to Dismiss, submitted on behalf of appellee, the Public Utilities Commission of Ohio, was served by regular U.S. mail, postage prepaid, or hand-delivered, upon the following parties of record, this 25th day of September 2012.

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APPENDIX

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4903.10 Application for rehearing.

After any order has been made by the public utilities commission, any party who has entered an appearance in person or by counsel in the proceeding may apply for a rehearing in respect to any matters determined in the proceeding. Such application shall be filed within thirty days after the entry of the order upon the journal of the commission. Notwithstanding the preceding paragraph, in any uncontested proceeding or, by leave of the commission first had in any other proceeding, any affected person, firm, or corporation may make an application for a rehearing within thirty days after the entry of any final order upon the journal of the commission. Leave to file an application for rehearing shall not be granted to any person, firm, or corporation who did not enter an appearance in the proceeding unless the commission first finds:

(A) The applicant's failure to enter an appearance prior to the entry upon the journal of the commission of the order complained of was due to just cause; and,

(B) The interests of the applicant were not adequately considered in the proceeding. Every applicant for rehearing or for leave to file an application for rehearing shall give due notice of the filing of such application to all parties who have entered an appearance in the proceeding in the manner and form prescribed by the commission. Such application shall be in writing and shall set forth specifically the ground or grounds on which the applicant considers the order to be unreasonable or unlawful. No party shall in any court urge or rely on any ground for reversal, vacation, or modification not so set forth in the application. Where such application for rehearing has been filed before the effective date of the order as to which a rehearing is sought, the effective date of such order, unless otherwise ordered by the commission, shall be postponed or stayed pending disposition of the matter by the commission or by operation of law. In all other cases the making of such an application shall not excuse any person from complying with the order, or operate to stay or postpone the enforcement thereof, without a special order of the commission. Where such application for rehearing has been filed, the commission may grant and hold such rehearing on the matter specified in such application, if in its judgment sufficient reason therefor is made to appear. Notice of such rehearing shall be given by regular mail to all parties who have entered an appearance in the proceeding. If the commission does not grant or deny such application for rehearing within thirty days from the date of filing thereof, it is denied by operation of law. If the commission grants such rehearing, it shall specify in the notice of such granting the purpose for which it is granted. The commission shall also specify the scope of the additional evidence, if any, that will be taken, but it shall not upon such rehearing take any evidence that, with reasonable diligence, could have been offered upon the original hearing. If, after such rehearing, the commission is of the opinion that the original order or any part thereof is in any respect unjust or unwarranted, or should be changed, the commission may abrogate or modify the same; otherwise such order shall be affirmed. An order made after such rehearing, abrogating or modifying the original order, shall have the same effect as an original order, but shall not affect any right or the enforcement of any right arising from or by virtue of the original order prior to the receipt of notice by the affected party of the filing of the application for rehearing. No cause of action arising out of any order of the commission, other than in support of the order, shall accrue in any court to any person, firm, or corporation unless such person, firm, or corporation has made a proper application to the commission for a rehearing.

4903.11 Proceeding deemed commenced.

No proceeding to reverse, vacate, or modify a final order of the public utilities commission is commenced unless the notice of appeal is filed within sixty days after the date of denial of the application for rehearing by operation of law or of the entry upon the journal of the commission of the order denying an application for rehearing or, if a rehearing is had, of the order made after such rehearing. An order denying an application for rehearing or an order made after a rehearing shall be served forthwith by regular mail upon all parties who have entered an appearance in the proceeding.

4903.13 Reversal of final order - notice of appeal.

A final order made by the public utilities commission shall be reversed, vacated, or modified by the supreme court on appeal, if, upon consideration of the record, such court is of the opinion that such order was unlawful or unreasonable. The proceeding to obtain such reversal, vacation, or modification shall be by notice of appeal, filed with the public utilities commission by any party to the proceeding before it, against the commission, setting forth the order appealed from and the errors complained of. The notice of appeal shall be served, unless waived, upon the chairman of the commission, or, in the event of his absence, upon any public utilities commissioner, or by leaving a copy at the office of the commission at Columbus. The court may permit any interested party to intervene by cross-appeal.

4903.15 Orders effective immediately - notice.

Unless a different time is specified therein or by law, every order made by the public utilities commission shall become effective immediately upon entry thereof upon the journal of the public utilities commission. Every order shall be served by United States mail in the manner prescribed by the commission. No utility or railroad shall be found in violation of any order of the commission until notice of said order has been received by an officer of said utility or railroad, or an agent duly designated by said utility or railroad to accept service of said order.

4903.16 Stay of execution.

A proceeding to reverse, vacate, or modify a final order rendered by the public utilities commission does not stay execution of such order unless the supreme court or a judge thereof in vacation, on application and three days' notice to the commission, allows such stay, in which event the appellant shall execute an undertaking, payable to the state in such a sum as the supreme court prescribes, with surety to the satisfaction of the clerk of the supreme court, conditioned for the prompt payment by the appellant of all damages caused by the delay in the enforcement of the order complained of, and for the repayment of all moneys paid by any person, firm, or corporation for transportation, transmission, produce, commodity, or service in excess of the charges fixed by the order complained of, in the event such order is sustained.

4909.18 Application to establish or change rate.

Any public utility desiring to establish any rate, joint rate, toll, classification, charge, or rental, or to modify, amend, change, increase, or reduce any existing rate, joint rate, toll, classification, charge, or rental, or any regulation or practice affecting the same, shall file a written application with the public utilities commission. Except for actions under section 4909.16 of the Revised Code, no public utility may issue the notice of intent to file an application pursuant to division (B) of section 4909.43 of the Revised Code to increase any existing rate, joint rate, toll, classification, charge, or rental, until a final order under this section has been issued by the commission on any pending prior application to increase the same rate, joint rate, toll, classification, charge, or rental or until two hundred seventy-five days after filing such application, whichever is sooner. Such application shall be verified by the president or a vice-president and the secretary or treasurer of the applicant. Such application shall contain a schedule of the existing rate, joint rate, toll, classification, charge, or rental, or regulation or practice affecting the same, a schedule of the modification amendment, change, increase, or reduction sought to be established, and a statement of the facts and grounds upon which such application is based. If such application proposes a new service or the use of new equipment, or proposes the establishment or amendment of a regulation, the application shall fully describe the new service or equipment, or the regulation proposed to be established or amended, and shall explain how the proposed service or equipment differs from services or equipment presently offered or in use, or how the regulation proposed to be established or amended differs from regulations presently in effect. The application shall provide such additional information as the commission may require in its discretion. If the commission determines that such application is not for an increase in any rate, joint rate, toll, classification, charge, or rental, the commission may permit the filing of the schedule proposed in the application and fix the time when such schedule shall take effect. If it appears to the commission that the proposals in the application may be unjust or unreasonable, the commission shall set the matter for hearing and shall give notice of such hearing by sending written notice of the date set for the hearing to the public utility and publishing notice of the hearing one time in a newspaper of general circulation in each county in the service area affected by the application. At such hearing, the burden of proof to show that the proposals in the application are just and reasonable shall be upon the public utility. After such hearing, the commission shall, where practicable, issue an appropriate order within six months from the date the application was filed.

If the commission determines that said application is for an increase in any rate, joint rate, toll, classification, charge, or rental there shall also, unless otherwise ordered by the commission, be filed with the application in duplicate the following exhibits:

(A) A report of its property used and useful, or, with respect to a natural gas company, projected to be used and useful as of the date certain, in rendering the service referred to in such application, as provided in section 4909.05 of the Revised Code;

(B) A complete operating statement of its last fiscal year, showing in detail all its receipts, revenues, and incomes from all sources, all of its operating costs and other expenditures, and any analysis such public utility deems applicable to the matter referred to in said application;

(C) A statement of the income and expense anticipated under the application filed;

(D) A statement of financial condition summarizing assets, liabilities, and net worth;

(E)

Such other information as the commission may require in its discretion.

4928.143 Application for approval of electric security plan - testing.

(A) For the purpose of complying with section 4928.141 of the Revised Code, an electric distribution utility may file an application for public utilities commission approval of an electric security plan as prescribed under division (B) of this section. The utility may file that application prior to the effective date of any rules the commission may adopt for the purpose of this section, and, as the commission determines necessary, the utility immediately shall conform its filing to those rules upon their taking effect.

(B) Notwithstanding any other provision of Title XLIX of the Revised Code to the contrary except division (D) of this section, divisions (I), (J), and (K) of section 4928.20, division (E) of section 4928.64, and section 4928.69 of the Revised Code:

(1) An electric security plan shall include provisions relating to the supply and pricing of electric generation service. In addition, if the proposed electric security plan has a term longer than three years, it may include provisions in the plan to permit the commission to

test the plan pursuant to division (E) of this section and any transitional conditions that should be adopted by the commission if the commission terminates the plan as authorized under that division.

(2) The plan may provide for or include, without limitation, any of the following:

(a) Automatic recovery of any of the following costs of the electric distribution utility, provided the cost is prudently incurred: the cost of fuel used to generate the electricity supplied under the offer; the cost of purchased power supplied under the offer, including the cost of energy and capacity, and including purchased power acquired from an affiliate; the cost of emission allowances; and the cost of federally mandated carbon or energy taxes;

(b) A reasonable allowance for construction work in progress for any of the electric distribution utility's cost of constructing an electric generating facility or for an environmental expenditure for any electric generating facility of the electric distribution utility, provided the cost is incurred or the expenditure occurs on or after January 1, 2009. Any such allowance shall be subject to the construction work in progress allowance limitations of division (A) of section 4909.15 of the Revised Code, except that the commission may authorize such an allowance upon the incurrence of the cost or occurrence of the expenditure. No such allowance for generating facility construction shall be authorized, however, unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Further, no such allowance shall be authorized unless the facility's construction was sourced through a competitive bid process, regarding which process the commission may adopt rules. An allowance approved under division (B)(2)(b) of this section shall be established as a nonbypassable surcharge for the life of the facility.

(c) The establishment of a nonbypassable surcharge for the life of an electric generating facility that is owned or operated by the electric distribution utility, was sourced through a competitive bid process subject to any such rules as the commission adopts under division (B)(2)(b) of this section, and is newly used and useful on or after January 1, 2009, which surcharge shall cover all costs of the utility specified in the application, excluding costs recovered through a surcharge under division (B)(2)(b) of this section. However, no surcharge shall be authorized unless the commission first determines in the proceeding that there is need for the facility based on resource planning projections submitted by the electric distribution utility. Additionally, if a surcharge is authorized for a facility pursuant to plan approval under division (C) of this section and as a condition of the continuation of the surcharge, the electric distribution utility shall dedicate to Ohio consumers the capacity and energy and the rate associated with the cost of that facility. Before the commission authorizes any surcharge pursuant to this division, it may consider, as applicable, the effects of any decommissioning, deratings, and retirements.

(d) Terms, conditions, or charges relating to limitations on customer shopping for retail electric generation service, bypassability, standby, back-up, or supplemental power service, default service, carrying costs, amortization periods, and accounting or deferrals, including future recovery of such deferrals, as would have the effect of stabilizing or providing certainty regarding retail electric service;

(e) Automatic increases or decreases in any component of the standard service offer price;

(f) Consistent with sections 4928.23 to 4928.2318 of the Revised Code, both of the following:

(i) Provisions for the electric distribution utility to securitize any phase-in, inclusive of carrying charges, of the utility's standard service offer price, which phase-in is authorized in accordance with section 4928.144 of the Revised Code;

(ii) Provisions for the recovery of the utility's cost of securitization.

(g) Provisions relating to transmission, ancillary, congestion, or any related service required for the standard service offer, including provisions for the recovery of any cost of such service that the electric distribution utility incurs on or after that date pursuant to the standard service offer;

(h) Provisions regarding the utility's distribution service, including, without limitation and notwithstanding any provision of Title XLIX of the Revised Code to the contrary, provisions regarding single issue ratemaking, a revenue decoupling mechanism or any other incentive ratemaking, and provisions regarding distribution infrastructure and modernization incentives for the electric distribution utility. The latter may include a long-term energy delivery infrastructure modernization plan for that utility or any plan providing for the utility's recovery of costs, including lost revenue, shared savings, and avoided costs, and a just and reasonable rate of return on such infrastructure modernization. As part of its determination as to whether to allow in an electric distribution utility's electric security plan inclusion of any provision described in division (B)(2)(h) of this section, the commission shall examine the reliability of the electric distribution utility's distribution system and ensure that customers' and the electric distribution utility's expectations are aligned and that the electric distribution utility is placing sufficient emphasis on and dedicating sufficient resources to the reliability of its distribution system.

(i) Provisions under which the electric distribution utility may implement economic development, job retention, and energy efficiency programs, which provisions may allocate program costs across all classes of customers of the utility and those of electric distribution utilities in the same holding company system.

(C)(1) The burden of proof in the proceeding shall be on the electric distribution utility. The commission shall issue an order under this division for an initial application under this section not later than one hundred fifty days after the application's filing date and, for any subsequent application by the utility under this section, not later than two hundred seventy-five days after the application's filing date. Subject to division (D) of this section, the commission by order shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. Additionally, if the commission so approves an application that contains a surcharge under division (B)(2)(b) or (c) of this section, the commission shall ensure that the benefits derived for any purpose for which the surcharge is established are reserved and made available to those that bear the surcharge. Otherwise, the commission by order shall disapprove the application.

(2)(a) If the commission modifies and approves an application under division (C)(1) of this section, the electric distribution utility may withdraw the application, thereby terminating it, and may file a new standard service offer under this section or a standard service offer under section 4928.142 of the Revised Code.

(b) If the utility terminates an application pursuant to division (C)(2)(a) of this section or if the commission disapproves an application under division (C)(1) of this section, the commission shall issue such order as is necessary to continue the provisions, terms, and conditions of the utility's most recent standard service offer, along with any expected increases or decreases in fuel costs from those contained in that offer, until a subsequent offer is authorized pursuant to this section or section 4928.142 of the Revised Code, respectively.

(D) Regarding the rate plan requirement of division (A) of section 4928.141 of the Revised Code, if an electric distribution utility that has a rate plan that extends beyond December 31, 2008, files an application under this section for the purpose of its compliance with division (A) of section 4928.141 of the Revised Code, that rate plan and its terms and conditions are hereby incorporated into its proposed electric security plan and shall continue in effect until the date scheduled under the rate plan for its expiration, and that portion of the electric security plan shall not be subject to commission approval or disapproval under division (C) of this section, and the earnings test provided for in division (F) of this section shall not apply until after the expiration of the rate plan. However, that utility may include in its electric security plan under this section, and the commission may approve, modify and approve, or disapprove subject to division (C) of this section, provisions for the incremental recovery or the deferral of any costs that are not being recovered under the rate plan and that the utility incurs during that continuation period to comply with section 4928.141, division (B) of section 4928.64, or division (A) of section 4928.66 of the Revised Code.

(E) If an electric security plan approved under division (C) of this section, except one withdrawn by the utility as authorized under that division, has a term, exclusive of phase-ins or deferrals, that exceeds three years from the effective date of the plan, the commission shall test the plan in the fourth year, and if applicable, every fourth year thereafter, to determine whether the plan, including its then-existing pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, continues to be more favorable in the aggregate and during the remaining term of the plan as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code. The commission shall also determine the prospective effect of the electric security plan to determine if that effect is substantially likely to provide the electric distribution utility with a return on common equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. The burden of proof for demonstrating that significantly excessive earnings will not occur shall be on the electric distribution utility. If the test results are in the negative or the commission finds that continuation of the electric security plan will result in a return on equity that is significantly in excess of the return on common equity that is likely to be earned by publicly traded companies, including utilities, that will face comparable business and financial risk, with such adjustments for capital structure as may be appropriate, during the balance of the plan, the commission may terminate the electric security plan, but not until it shall have provided interested parties with notice and an opportunity to be heard. The commission may impose such conditions on the plan's termination as it considers reasonable and necessary to accommodate the transition from an approved plan to the more advantageous alternative. In the event of an electric security plan's termination pursuant to this division, the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan.

(F) With regard to the provisions that are included in an electric security plan under this section, the commission shall consider, following the end of each annual period of the plan, if any such adjustments resulted in excessive earnings as measured by whether the earned return on common equity of the electric distribution utility is significantly in excess of the return on common equity that was earned during the same period by publicly traded companies, including utilities, that face comparable business and financial risk, with such adjustments for capital structure as may be appropriate. Consideration also shall be given to the capital requirements of future committed investments in this state. The burden of proof for demonstrating that significantly excessive earnings did not occur shall be on the electric distribution utility. If the commission finds that such adjustments, in the aggregate, did result in significantly excessive earnings, it shall require the electric distribution utility to return to consumers the amount of the excess by prospective adjustments; provided that, upon making such prospective adjustments, the electric distribution utility shall have the right to terminate the plan and immediately file an application pursuant to section 4928.142 of the Revised Code. Upon termination of a plan under this division, rates shall be set on the same basis as specified in division (C)(2)(b) of this section, and the commission shall permit the continued deferral and phase-in of any amounts that occurred prior to that termination and the recovery of those amounts as contemplated under that electric security plan. In making its determination of significantly excessive earnings under this division, the commission shall not consider, directly or indirectly, the revenue, expenses, or earnings of any affiliate or parent company.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Duke Energy Ohio, Inc. and	)	**Docket No. ER10-2254-000**
Duke Energy Kentucky, Inc.	)	

Duke Energy Answer and Motion for Leave to Answer

Most of the comments submitted in response to Duke Energy Ohio's ("DEO") August 16, 2010 Fixed Resource Requirement ("FRR") Plan Filing in this docket request clarification about how a particular aspect of the FRR Plan will work. A few entities protested or sought clarification with respect to use of the Reliability Pricing Model ("RPM") price as a benchmark for pricing capacity sales.

As discussed in Section I below, PJM's Reliability Assurance Agreement ("RAA") requires DEO to offer the RPM price to alternative retail electric suppliers under DEO's FRR plan. The RAA also provides alternative retail suppliers with the opportunity to self-supply in the event that they believe they can obtain a lower price elsewhere. DEO has not requested modification or waiver of either of these pre-existing RAA provisions.

DEO also has not requested that the Commission effectively dictate retail rates by determining that DEO must "take service from itself" at the RPM price. DEO has not yet even initiated a case to set retail electric generation rates for the period beginning when DEO joins PJM. Principles of Federal-State comity weigh in favor of allowing issues regarding retail rate components for capacity to be addressed, in the first instance, in a state proceeding. Thus, the concerns of the Office of the Ohio Consumer Counsel ("OCC") about impacts of our proposal on DEO retail ratepayers in the first five months of 2012 are unfounded, unripe, and fundamentally a state rate issue rather than an issue for this Commission. And in any event, as we discuss below, use of the RPM

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price for that period is supported both by the RPM design and because it meets the criteria for a relevant price benchmark. The Commission has established that it is just and reasonable to apply the RPM price to all other load in PJM to assure reliability during that period, so surely it is just and reasonable to apply it also to newly entering load to achieve the same purpose, for the same period, in the same market.

In Section II we specifically address the questions of a factual nature that were submitted in the comments in this docket. We also have worked with PJM and its stakeholders in a stakeholder meeting as well as in individual communications to address stakeholder questions. PJM has posted the resulting Q&As and associated information on its website so that all may benefit from the information provided.

In Section III we address a hold harmless claim raised by the Indiana Municipal Power Agency ("IMPA") relating to service from its generation in the Midwest ISO to load in the DEO footprint after the RTO Realignment. As we explain, IMPA has failed to articulate a *prima facie* claim for hold harmless treatment, but we are not asking that the claim be rejected at this time. Rather, consistent with our approach to these issues throughout the RTO Realignment process, we are requesting that any decision on the merits be deferred until the Commission has all of the information it needs to make an informed decision, which will not occur until after DEO makes a filing proposing its PJM zonal transmission rate. In the meantime, the parties can continue to pursue settlement. We also recommend that the Commission consider directing the Midwest ISO and PJM to work together "to support reasonable arrangements to permit" entities such as IMPA with capacity resources in the Midwest ISO "to utilize [that] capacity in satisfying [their] reliability obligations" in PJM after DEO joins PJM, much as the

Commission did in analogous circumstances when Duquesne proposed to leave PJM to join the Midwest ISO.[1]

I. Concerns About Use of RPM Pricing Are Misplaced

DEO has proposed to offer to sell capacity to wholesale loads that do not choose to self-supply at a price benchmarked to the RPM price.[2] This is the same price that other load-serving entities in PJM will be paying to assure reliability during the same period. The RPM price is a market-determined price established through an auction process subject to mitigation of supply offer prices to address market power concerns. PJM's Independent Market Monitor reviewed our proposal to benchmark to the RPM price before it was filed and did not object.[3] In any event, DEO is required, under the RAA, to sell capacity to alternative retail suppliers at the RPM price,[4] if they do not choose to self-supply.

The OCC argues that the RPM price is too high for the first five months of the FRR Plan period.[5] The OCC is concerned about pass-through of RPM costs during these five months to DEO's "Ohio residential consumers."[6] But DEO was careful in its

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1 *Duquesne Light Company*, 122 FERC ¶ 61,039 at P 93 (2008); Order on Emergency Motion for Clarification, 123 FERC ¶ 61,060, Order Addressing Conditional RTO Withdrawal Request, as Revised, Proposed Integration Plan, Requests for Rehearing, and Compliance with Prior Rulings, 124 FERC ¶ 61,219, Order Denying Clarification and Reh'g, 125 FERC ¶ 61,141 (2008).

2 FRR Plan Filing at 3-4, 12-13.

3 *Id.*, at 11.

4 Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region, Rate Schedule FERC No. 44, Schedule 8.1, Section D.8 ("RAA").

5 Motion to Intervene and Protest of the Office of the Ohio Consumers' Counsel, Docket No. ER10-2254-000 at 4-5 (filed Sept. 7, 2010) ("OCC").

6 *Id.*, at 2.

FRR Plan Filing to limit its pricing proposal to sales at wholesale. DEO has not asked this Commission to require DEO to "charge itself" the RPM rate, because that would be premature in light of the fact that DEO has not yet even initiated a ratemaking proceeding to set retail electric generation rates for the FRR Plan period.[7] Similarly, requests from alternative retail suppliers that the Commission affirmatively require DEO to charge RPM as its retail rate to "level the playing field,"[8] or provide data on the derivation of the retail rate,[9] are also premature, particularly given the fact that alternative retail suppliers can choose to self-supply if they do not want to pay DEO the RPM price.[10]

The OCC asserts that prices should be lower in the spring than in the summer. That is not how RPM works. RPM reliability requirements, though established based

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[7] DEO's principle reason for making the move from the Midwest ISO to PJM on January 1, 2012 is that that date will be the start of the period for DEO's next retail rate plan for electric generation service. DEO's current retail rate plan for electric generation service provides a fixed, average rate for recovery of costs that include costs of DEO-owned capacity, and that rate does not vary by day or even by season. It certainly does not include any sort of down payment on capacity for the next retail rate period – the period that begins on January 1, 2012. Thus, the OCC's implication that retail ratepayers in Ohio will somehow have paid in advance for the costs for capacity to be used for reliability purposes after January 1, 2012 is unfounded.

[8] Motion to Intervene, Protest, and Comments of Dominion Resources Services, Inc., Docket No. ER10-2254-000 at 7 (filed Sept. 7, 2010).

[9] Motion to Intervene and Comments of FirstEnergy Solutions Corp., Docket No. ER10-2254-000 at 2 (filed Sept. 7, 2010) ("FirstEnergy"). If FirstEnergy is seeking cost data, such data would be relevant at the wholesale level only if our proposal was a cost-based proposal. As explained in the FRR Plan Filing any sale of capacity made by DEO to a wholesale load would occur under DEO's market-based rate tariff. *See* FRR Plan Filing at n. 25. *Cf. also Atlantic City Electric Company*, 86 FERC ¶ 61,248 at 61,906 (1999) ("[e]ntities that do not have any tariff on file authorizing sales under market-based rates must make a filing under section 205 before selling energy or ancillary services into the PJM PX").

[10] FRR Plan Filing at 13. Of course, if alternative retail suppliers obtain new switched load beyond the amount of load they "opt out," they will pay DEO the RPM price for that load to compensate DEO for its commitment of resources to serve that load. Under the PJM tariff, when load switches to an alternative retail supplier, that supplier must pay the RPM price to meet the new load's capacity requirement. *See* n.11 below. Our proposal tracks this feature.

upon summer peak loads, are the same every day of the year, in every season.[11] As a result, the price paid for capacity also is the same for every day of the entire year, notwithstanding that capacity prices in secondary markets might fluctuate during that period.[12] If it were unjust and unreasonable to charge the RPM price to loads in PJM in off-peak periods such as the Spring of 2012, then the RPM price for the Spring of 2012 would be different, and we would be benchmarking to that different RPM price.

The logical fallacy of the OCC's position is shown by reference to RPM itself. When a load switches to a new alternative provider under RPM, the new alternative retail provider pays the RPM price on behalf of that load.[13] So if, for example, a load switched to a new provider on January 1, 2012, that new provider would pay the full RPM price for each month of the remainder of the 2011–2012 Delivery Year even though it was not providing capacity to that load during the summer peak of 2011. That approach makes sense because, regardless of the supplier, there needs to be sufficient capacity to assure reliable service to the load on an annual basis.

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11 The "Daily Unforced Capacity Obligation" is "the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement." PJM Tariff, Att. DD § 2.18. Schedule 8 of the RAA provides that the Daily Unforced Capacity Obligation is determined based on the weather-adjusted coincident summer peak, multiplied by other factors. RAA, Schedule 8, Section A. Per Section 9.2.1 of PJM Manual 18, "All LSEs pay a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in a zone times the applicable Final Zonal Capacity Price."

12 "In accordance with the Reliability Assurance Agreement, each Load Serving Entity is obligated to pay a Locational Reliability Charge for each Zone in which it serves load based on the Daily Unforced Capacity Obligation of its loads in such Zone." PJM Tariff, Att. DD § 5.1; "In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets as described in sections 5.13 and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone." PJM Tariff, Att. DD § 5.14(e).

13 *See* n.11, above.

The need for capacity to maintain reliability in the DEO footprint will not materialize suddenly when DEO joins PJM. That need exists in the Midwest ISO, and DEO's generation will be self-supplied to meet that need in the Summer of 2011. The only real difference is that the level of price *transparency* provided by RPM does not exist in the Midwest ISO.[14] So like the Midwest ISO in its protest of our Initial Filing, the OCC appears to be attempting to create a "sticker shock" argument that plays off the transition from a non-transparent price for capacity to a transparent price to create an impression of unfairness. But so long as the RPM price is a just and reasonable price for the cost of maintaining reliability in PJM, there can be no serious argument that it is not a just and reasonable price for new entrants to the region to obtain the same result.

The OCC points to prices from PJM Incremental Auctions and argues that prices for capacity, once DEO moves to PJM, should be lower than the PJM RPM price.[15] But to the extent that PJM has been able to secure some portion of the capacity requirement for the 2011–2012 period at lower costs through the Incremental Auctions, this savings has already been factored into DEO's proposal to charge the "Final Zonal Capacity Price" rather than the clearing price from the Base Residual Auction.[16] The Final Zonal Capacity Price is a weighted average rate that blends the prices from the Base Residual Auction for the Delivery Year in question with the prices obtained in

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14 As described below, the Midwest ISO's Voluntary Capacity Auction is a residual device that is not robustly traded and does not accurately reflect the value of capacity, particularly capacity such as DEO's that is self-supplied and not cleared through the market. More than 98% of capacity requirements in the Midwest ISO were filled bilaterally or through self supply during the first five months of 2010 (the period used by the OCC for its price comparison).

15 OCC at 7.

16 FRR Plan Filing at n.19.

Incremental Auctions for the same Delivery Year.[17] Thus, the Incremental Auction results will in fact proportionally influence the price paid under the Duke FRR Plan.

The OCC's contention that prices should be set based on historical prices in the Midwest ISO's monthly Voluntary Capacity Auctions amounts to a claim that those thinly-traded, dated prices are a better measure of the future value of capacity than PJM's forward-looking capacity price for determining the price that load in PJM should pay. The Commission is not permitted to substitute a "better" rate so long as the proposed rate falls within the statutory zone of reasonableness.[18] There is no contention by the OCC that RPM prices are not in fact just and reasonable, nor could such contention carry the day in light of the substantial evidentiary record on RPM.[19]

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17 *See* PJM Tariff, Att. DD § 5.14(f)(iii) ("The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted (for the Delivery Years through May 31, 2012) to reflect the certified ILR compared to the ILR Forecast previously used for such Delivery Year, and any decreases in the Nominated Demand Resource Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction."); PJM Tariff, Att. DD § 5.14(f)(ii) ("The Adjusted Zonal Capacity Price for each Zone shall equal (1) the sum, for all auctions previously conducted for such Delivery Year, of the Resource Clearing Price for each auction times the Unforced Capacity cleared for such auction (excluding any Unforced Capacity cleared as replacement capacity), divided by (2) the sum of the Unforced Capacity cleared in all such auctions (excluding any Unforced Capacity cleared as replacement capacity), plus an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity). The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.").

18 *See, e.g., Entergy Services, Inc.*, 130 FERC ¶ 61,026 (2010) ("the appropriate inquiry in reviewing rate changes proposed pursuant to section 205 is whether '[t]he filing meets the statutory standard, not whether alternatives offered by intervenors are better . . . [t]he proposed provisions need be neither perfect nor even the most desirable; they need only be just and reasonable and not unduly discriminatory or preferential.'" (citing Presiding Judge quoting *American Elec. Power Serv. Corp. v. FERC*, 116 FERC ¶ 61,179, at 61,757 (2006)); *Louisville Gas & Elec. Co.*, 114 FERC ¶ 61,282 at P 29 (2006) ("the just and reasonable standard under the FPA is not so rigid as to limit rates to a "best rate" or "most efficient rate" standard. Rather, a range of alternative approaches often may be just and reasonable") ("*LG&E Withdrawal Order*").

19 *See PJM Interconnection, L.L.C.*, Order Denying Reh'g and Approving Settlement Subject to Conditions, 117 FERC ¶ 61,331 (2006); Order on Reh'g and Clarification and

(cont'd)

Rather, the OCC is claiming that it is not just and reasonable to use the RPM price as a benchmark for pricing capacity for five months under the Duke FRR Plan, notwithstanding the uncontested fact that this same RPM price is a just and reasonable price to charge to every other load-serving entity in PJM for these five months.

The Midwest ISO rates cited by OCC are not "better" or somehow "more" reasonable than PJM's RPM rate. The Commission has useful experience in determining when a price index, such as an RTO clearing price, is appropriate for use as a benchmark for pricing another transaction. Specifically, an affiliate transaction will be authorized if it is benchmarked to an index price that meets criteria set forth in Commission policy.[20] An RTO index is "acceptable benchmark evidence and mitigates affiliate abuse concerns so long as that benchmark price or index reflects the market price where the affiliate transaction occurs (i.e., is a relevant index)."[21]

Contrary to the OCC's contention, PJM's RPM price for delivery to loads in PJM in the spring of 2012 provides a more relevant index benchmark for the wholesale capacity charge for the PJM loads in the DEO zone in the spring of 2012 than Midwest ISO prices from the Spring of 2010. First, the location is not the same. During the FRR

(cont'd from previous page)
Accepting Compliance Filing, 119 FERC ¶ 61,318 (2007); Order Denying Reh'g, 121 FERC ¶ 61,173 (2007); *Petition for review denied without opinion, Public Service Electric & Gas Company, et al. v. FERC*, 324 Fed. Appx. 1 (2009).

20 *See, e.g., Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 119 FERC ¶ 61,295 at P 542 (2007) ("Order No. 697"); order on reh'g and clarification, Order No. 697-A, 123 FERC ¶ 61,055 (2008); order on reh'g and clarification, 124 FERC ¶ 61,055 (2008); order on reh'g and clarification, Order No. 697-B, 125 FERC ¶ 61,326 (2008); order on reh'g and clarification, Order No. 697-C, 127 FERC ¶ 61,284 (2009); order on reh'g and clarification, Order No. 697-D, 130 FERC ¶ 61,206 (2010); order on request for clarification, 131 FERC ¶ 61,021 (2010).

21 *Id. See also, e.g., Brownsville Power I, L.L.C.*, 111 FERC ¶ 61,398 at P 10 (2005) ("*Brownsville*") ("[t]ying the price of an affiliate transaction to an established, relevant market price adequately mitigates any affiliate abuse concerns") (citations omitted).

Plan period, DEO will be in PJM, not the Midwest ISO. Thus, the price in the Midwest ISO will not be the "price where the ... transaction occurs."[22] Perhaps it might nonetheless be argued that the Midwest ISO Voluntary Capacity Auction represents a market that will remain geographically "relevant" to DEO once it is in PJM. But the Midwest ISO price will be a price from a different market, with different obligations, penalties and charges. Surely the RPM price from the *same* geographic market – i.e., the "price where the ... transaction occurs" – will not be *less* relevant. In fact, in 2005 the Commission examined the (geographically) reverse situation and concluded that the newly-established Midwest ISO Cinergy Hub index was a "more relevant index" to benchmark sales among Cinergy affiliates than the PJM Southwest Interface index price "because Cinergy Utilities as purchasers are located in the Midwest ISO."[23] Here, the load purchasing capacity to meet reliability obligations will be in PJM, making PJM's RPM the "more relevant index."[24]

Second, the capacity prices that the OCC references were established in a substantially different time period from the time when the DEO zone in PJM will need capacity. The OCC argues that Midwest ISO auction prices referenced by the OCC, which apply to a delivery period over a span of months in the first half of 2010,[25] should somehow stand as a reasonable proxy for the value of a capacity product that will be required by customers in the DEO zone in PJM for delivery some two years later, in the

22 Order No. 697 at P 542.

23 *Brownsville*, 111 FERC ¶ 61,398 at P 10.

24 *Id.*

25 *See* OCC at 7. The OCC selected the first five months (January to May) for price comparison.

first half of 2012. But surely the RPM price for delivery of capacity in the *same* time period in which customers in the DEO footprint will require capacity is not *less* relevant.

Third, the Midwest ISO capacity prices cited by the OCC were set in thinly-traded markets, in sharp contrast to the large and robust capacity markets in PJM. The Commission's policy on price indexes requires that the index be robustly traded.[26] While an RTO market is generally deemed to satisfy this test, comparison between the Midwest ISO's Voluntary Capacity Auction and the PJM RPM process is illuminating. The Brattle Group report cited by the OCC states that the Midwest ISO's Voluntary Capacity Auction "exhibited low volumes and widely varying prices."[27] The Voluntary Capacity Auction "is a residual market covering only a small fraction of the market."[28] Indeed, the "average cleared volume in the [Voluntary Capacity Auction] is only 0.7% of the system summer peak, and only 1.9% of the volume of bilateral [Planning Resource Credits] traded."[29]

The authors of the report suggest that "[t]hese low volumes could be because many LSEs prefer to procure most of their seasonal capacity needs several months in advance rather than through the auction right before the planning deadline."[30] The low

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26 *See, e.g.*, Order No. 697 at P 543 ("while the Commission has found in the past that certain non-RTO price indices are acceptable indicators of market prices, we continue to recognize that price indices at thinly traded points can be subject to manipulation and are otherwise not good measures of market prices as discussed in the Price Index Policy Statement"); *Richmond County Power, LLC*, 96 FERC ¶ 61,149 (2001) (rejecting use of thinly-traded price indices for purposes of benchmarking affiliate transaction prices).

27 The Brattle Group, Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements, January 19, 2010, at 44, *available at* http://www.brattle.com/_documents/uploadlibrary/upload832.pdf.

28 *Id.*

29 *Id.*

30 *Id.*

volumes may be consistent with the Midwest ISO's market design "since MISO is primarily a bilateral market and the [Voluntary Capacity Auction] was never intended to replace bilateral activity. The [Voluntary Capacity Auction] was only intended to serve as a balancing market."[31] The report recommends continued study and states that "[m]any stakeholders have expressed a lack of confidence" in the Voluntary Capacity Auction results.[32] As the Commission has said, "[s]ince index dependencies permeate the energy industry, the indices must be robust and accurate and have the confidence of market participants for such markets to function properly and efficiently."[33]

By contrast, all capacity required to meet PJM's non-FRR reliability requirements – more than 130,000 MW for Delivery Year 2011-12[34] – clears in the Base Residual Auction or a subsequent Incremental Auction. And as explained above, it is the weighted averaging of the results from that set of auctions for a Delivery Year that produces the Final Zonal Capacity Price that DEO plans to charge to wholesale load that does not choose to self-supply. Thus, even if the Midwest ISO's Voluntary Capacity Auction is sufficiently robust to serve as a benchmark for pricing purposes, it is simply not credible to argue that it is more robust, or a better benchmark, than PJM's RPM.

In sum, the Midwest ISO's Voluntary Capacity Auction does not provide a "better" benchmark for capacity in DEO's FRR auction than the more relevant PJM RPM price.

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31 *Id.*

32 *Id., at* 43-44.

33 *Price Discovery in Natural Gas and Electric Markets*, Policy Statement on Natural Gas and Electric Price Indices, 104 FERC ¶ 61,121 at P 6 (2003).

34 *See* http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2009-2010-base-residual-auction-report.ashx.

The PJM Incremental Auctions also do not provide a "better" price on a stand-alone basis, because the prices from those auctions already are factored in, on a weighted average basis, to the RPM Final Zonal Capacity Price that DEO proposes to use as its benchmark. And in any event, the notion that some "better" price is needed is without merit. Load serving entities in PJM must supply the same quantity of capacity to meet reliability requirements every day of the year, and as a consequence they must pay the same RPM price every day of the year that they serve load, regardless of whether they were serving that load during the summer peak. Thus, not only is the RPM price the price specified to be charged by PJM's Reliability Assurance Agreement in situations like this, RPM is the best available benchmark for the price of capacity to meet reliability requirements in PJM every day of the year.

II. Responses to Questions Regarding Operation of FRR Plan

On Friday, September 17, 2010, PJM conducted a stakeholder meeting concerning the RTO Realignment in Cincinnati, Ohio. Approximately 30 stakeholders were present at that meeting and another 80 registered to participate by phone. At the meeting, PJM made a presentation providing stakeholders with information about the integration of DEO and DEK into PJM, and how it will affect stakeholders, covering topics such as Financial Transmission Rights (FTR), RPM and RTEP transition, as well as transmission service conversion. The slides used for the presentation are a good resource for stakeholders to find answers regarding their questions. It can be found at http://pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/duke.aspx. PJM also has a "frequently asked questions" document posted on its website the records questions and answers from stakeholders, including questions that were asked directly of Duke Energy. That document can be found at http://pjm.com/markets-and-operations/market-integration/duke.aspx, and will be updated by PJM as more questions are received by PJM and/or Duke Energy.

PJM has also posted a question & answer document prepared by Duke Energy that seeks to specifically answer the factual questions presented in the comments and protests to the FRR Plan Filing. That document can be found at *http://pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/duke.aspx*. The question & answer document was provided to stakeholders at the September 17 PJM stakeholder meeting, and reviewed with the stakeholders by a Duke Energy representative. No stakeholders commented or asked further questions at the time.[35] For example, the Duke Energy representative specifically asked whether stakeholders would be opposed to DEO's proposal to withdraw a waiver request as discussed in question (4) below. Since no objection was expressed, DEO hereby withdraws that waiver request.[36]

The following question and answers regarding operation of the FRR plan are substantively identical to those shared at the PJM stakeholder meeting, although additional details on dynamic scheduling under the PJM tariff have been provided in response to question (5).

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35 Duke Energy does not mean to imply that stakeholders were under an obligation to comment at the time if they had reservations about our answers. They were not. Rather, we simply wish to demonstrate that our commitment to addressing these sorts of issues runs beyond filing of pleadings with the Commission.

36 Specifically, DEO withdraws its request, on pages 17-18 of the FRR Plan Filing, for waiver with respect to Section F.2 of Schedule 8.1 of the RAA to the extent that it would impose a FRR Capacity Deficiency Charge on a Demand Resource Provider when its resources are no longer available to support the Demand Resource Provider's capacity obligation because of the permanent departure of the load resource associated with the obligation.

1. **Will parties who "self-serve" be able to do so for parts of the FRR plan (deliver year blocks) less than the total 29-month transition period? (*See, e.g.*, FirstEnergy,[37] AMP-Ohio[38]) Also, will LSEs be allowed to satisfy a portion of their capacity obligations with their own resources and the remaining with resources acquired from DEO through the Duke FRR plan? (AMP-Ohio[39])**

    - Response: All loads will have the option to self-supply. The means of self-supply, and the flexibility associated with that means, are established by PJM's reliability assurance agreement ("RAA").

    - As stated on page 14 of the Duke FRR Filing, alternative retail suppliers have an option, per section D.9 of Schedule 8.1 of the RAA, to procure their own supply, which we call the "opt-out" option. The RAA specifically provides that such elections may be made on a delivery year basis. The RAA does not specify whether an alternative retail supplier may opt-out for part of its load or all of it. We propose to allow opt-outs for partial loads to promote flexibility.

    - Other wholesale loads may self-supply by entering into their own FRR plans.[40] Typically there is a minimum five-year period for an FRR plan in PJM.[41] However, given the unique integration-related context of our FRR proposal, we have requested waiver of the minimum five-year term to allow FRR plans for DEO and other affected FRR entities to run only for the 29 month period prior to RPM integration. Thus, we proposed two FRR self-supply alternatives:

        - They can enter into a traditional FRR plan, per the terms of the RAA (*e.g.*, with the minimum five year term contemplated by the RAA); or

        - They can (with the Commission's permission, which permission DEO and DEK have sought in this proceeding on their behalf) enter into an out-of-time FRR Plan designed to see them through the 29

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37 FirstEnergy at 2.

38 Motion to Intervene and Comments of American Municipal Power, Inc., Docket No. ER10-2254-000 at 6-8 (filed Sept. 7, 2010) ("AMP-Ohio").

39 *Id.*

40 Per RAA Schedule 8.1, Section B.1, "a Party [that did not previously select FRR status under another now-expired eligibility option] is eligible to select the FRR Alternative if it (a) is an IOU, Electric Cooperative, or Public Power Entity; and (b) demonstrates the capability to satisfy the Unforced Capacity obligation <u>for all load in an FRR Service Area, including all expected load growth in such area</u>, for the term of such Party's participation in the FRR Alternative." (emphasis added).

41 Section C.1 of Schedule 8.1 of the RAA provides that the election of a Party of the FRR Alternative "shall be for a minimum term of five consecutive Delivery Years."

month transition period before they can participate in RPM, with all of the waivers and adjustments that we seek in this filing to make such an out-of-time FRR Plan possible, but otherwise the same as a traditional FRR plan.

- o DEO and DEK did not request waiver of the five-year minimum FRR period for FRR plans to run less than 29 months. Nor did DEO/DEK request any waiver that would permit LSEs serving wholesale load to submit an independent FRR plan for a partial amount of their capacity obligation. We note that the waiver requests we made on behalf of independent FRR entities were intended to be helpful, not to constrain the ability of independent FRR entities to make alternative waiver requests on their own behalf.

2. **Explain how DEO will bill the proposed index price to third-party suppliers who serve wholesale or retail load in the Ohio footprint. (*See* FirstEnergy[42])**

    - Response. Pursuant to Schedule 8.1 of the RAA, DEO is required to fulfill the FRR capacity needs of alternative retail electric suppliers serving switched load. DEO will serve such load at the RPM price, as provided for in RAA Section D.8 of Schedule 8.1, unless the alternative retail LSE supplies its own capacity pursuant to an election and commitment made under Section D.9 of Schedule 8.1. As stated on page 15 of the FRR Filing,[43] such sales will be made under DEO's market-based rate tariff. Procedurally, PJM will act as the billing agent for DEO for sales of capacity to such alternative retail suppliers.

    - Specifically, the RAA states:

      "PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism."

3. **Explain Duke's request for waiver regarding summer compliance testing of Demand Resources and measurement of Energy Efficiency Resources for the partial year Jan 1, 2012 to May 31, 2012. (*See, e.g.,* PSEG[44])**

    - Response: It is not clear to DEO/DEK how PJM could test demand resources in the summer of 2011, since those resources will still at that time be in the Midwest ISO. Thus, we have proposed that PJM be required to use its reasonable judgment in determining, for that very limited time period from January 1, 2012 to May 31, 2012, which DR and EE resources can satisfy reliability requirements, if any. PJM is in the

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42 FirstEnergy at 1-2.

43 *See* footnote 25 of FRR Filing.

44 Motion to Intervene and Comments of the PSEG Companies, Docket No. ER10-2254-000 at 4-5 (filed Sept. 7, 2010).

process of comparing its testing, measurement and verification requirements with those of the Midwest ISO, to ascertain whether they are sufficiently similar, in PJM's sole judgment, such that allowing these resources to participate in the FRR Plan will not cause PJM to fail to satisfy its reliability requirements.

4. **In its comments PSEG questions the propriety of the waiver DEO sought with respect to Section F.2 of Schedule 8.1 of the RAA to the extent that it would impose a FRR Capacity Deficiency Charge on a Demand Resource Provider when its resources are no longer available to support the Demand Resource Provider's capacity obligation because of the permanent departure of the load resource associated with the obligation.[45] PSEG also wants to know whether it is a permanent waiver request for all DRPs in the DEO/DEK zones.[46]**

    - Response. The proposed waiver request in question is intended to continue for the FRR transitional period only, and to provide maximum flexibility for affected stakeholders during that timeframe. That said, to date no parties have expressed an interest in that particular waiver request. As a result, and in light of the considerations raised in PSEG's comments, DEO proposes to withdraw this waiver request.

5. **Explain the process for pseudo-tying facilities from PJM to the Midwest ISO. (*See* PSEG[47])**

    - Response. The Midwest ISO tariff contains provisions regarding the criteria for maintaining pseudo-ties to the Midwest ISO. First, the Midwest ISO tariff provides that regulation, spin, and supplemental qualified resources in the day-ahead energy and operating reserve market either be physically located within the Midwest ISO balancing authority area or be pseudo-tied into Midwest ISO and remain pseudo-tied until the next Network Model update.[48] The Midwest ISO also provides that load external to the Midwest ISO Balancing Authority Area may be included as part of the Transmission Provider Region if that Load registers through an existing Local Balancing Authority (LBA) and pseudo-ties into the Midwest Balancing Authority Area through that existing LBA.[49]

    - The PJM Tariff indicates that in order to provide Synchronized Reserve, Day-ahead Scheduling Reserves, etc. a unit must be electrically located in the PJM Balancing Authority.[50] PJM interprets "electrically located" to

45 *Id.*, at 5.

46 *Id.*

47 *Id.*, at 6.

48 Midwest ISO Tariff §§ 39.2.1B.a, b, and c.

49 *Id.*, § 39.2.3.

50 PJM Tariff, Attachment K – Appendix §§ 1.3.1D.03, 1.3.33B.01.

mean either physically connected to the PJM Region or either pseudo-tied or dynamically scheduled into PJM. The PJM Tariff also provides for dynamic scheduling.[51] PJM considers dynamic schedules and pseudo-ties to be the same thing, although the Midwest ISO does not.

- With respect to dynamic scheduling, Section 1.12 of Attachment K – Appendix of the PJM Tariff provides that:

> "(a) An entity that owns or controls a generating resource in the PJM Region may request that the Transmission Provider electrically remove all or part of the generating resource's output from the PJM Region through dynamic scheduling of the output to load outside the PJM Region. Such output shall not be available for economic dispatch by the Office of the Interconnection. A generating unit otherwise eligible pursuant to section 3.2.3 to submit start-up and no-load values for consideration in calculation of the Operating Reserve Credit shall not be so eligible if all of the output of the unit is dynamically scheduled outside of the PJM Region.
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> * * *
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> (c) The Transmission Provider shall implement dynamic scheduling pursuant to a request under subsections (a) or (b) above, provided that the requesting entity can demonstrate to the satisfaction of the Transmission Provider that the requesting entity has arranged for the provision of signal processing and communications from the generator to the Office of the Interconnection and other participating control areas and remains in compliance with any other procedures and operational requirements established by the Office of the Interconnection regarding dynamic scheduling as set forth in the PJM Manuals.
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> (d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of firm or non-firm transmission service necessary to deliver the range of the dynamic transfer and any required ancillary services.
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> (e) The generating unit shall cooperate with PJM to ensure that changes in the dynamic schedule value do not adversely impact PJM's management of the PJM Area Control Error in a manner unacceptable to PJM, and, in the event that PJM, in its sole discretion, determines that the generating unit's actions in this regard are unacceptable, PJM may terminate the dynamic scheduling arrangement

[51] PJM Tariff, Attachment K – Appendix § 1.12.

and may require such additional conditions as it deems appropriate prior to any further dynamic scheduling.

6. **Explain the treatment of existing transmission and interconnection service, and of transmission and interconnection service requests, and application of "hold harmless" (*e.g.*, IMPA, EKPC, AMP-Ohio[52]). Explain the determination of deliverability from existing resources (AMP-Ohio[53]).**

    - Response. As stated in the Initial Filing DEO and DEK expect to submit a number of future filings as part of the proposed RTO Realignment, including additional filings in the Summer or Fall of 2011 to address transition of transmission service, generator and load interconnection queues, generator deactivation requests, and existing agreements.

    - It is our understanding that PJM will treat existing interconnection agreements in a manner similar to which they are being treated for the ATSI integration. Specifically, generators with existing interconnection agreements and in service as of the integration date will be deliverable in PJM upon integration. If the generator received energy resource interconnection service in MISO it will retain its energy only status. If the generator received network resource interconnection service in MISO it will retain capacity rights in PJM. For two-party interconnection agreements, upon integration those agreements will be provided with a PJM service agreement number and will be bound by the terms of PJM's Tariff. For three-party interconnection agreements, they must first be assigned from MISO to PJM after which PJM will assume the role of Transmission Provider under those agreements. However, before PJM will accept assignment of such agreements it will review them to determine whether they contain any terms and conditions for which the Transmission Provider is responsible that are inconsistent with PJM's standard interconnection service agreement located in Attachment O to PJM's Tariff. In such case, the generator will be given the option to enter into PJM's standard form of interconnection service agreement, amend their current agreements to address the inconsistencies or condition the assignment of the agreement on the generator agreeing to a supremacy provision pursuant to which PJM's Tariff and Manuals will prevail where there are inconsistencies.

    - All hold harmless issues should be addressed as part of planned future DEO/DEK filings. As stated in the DEO/DEK Answer in Docket No. ER10-1562-000, pursuant to the *LG&E* standard the "hold harmless" obligations

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52 Intervention and Protest of the Indiana Municipal Power Agency, Docket No. ER10-2254-000 at 4-5 (filed Sept. 7, 2010) ("IMPA"); Motion to Intervene of the East Kentucky Power Cooperative, Inc., Docket No. ER10-2254-000 at 2 (filed Sept. 3, 2010) ("EKPC"); AMP-Ohio at 9-10.

53 AMP-Ohio at 9-10.

apply to "existing" transmission contracts for the remaining term of such contracts.[54] According to FERC, a transmission reservation only qualifies for hold harmless treatment if it was confirmed before the withdrawing entity gave notice of the withdrawal to the Midwest ISO. Thus, no transmission reservation will qualify for hold harmless treatment if it was confirmed by the Midwest ISO after May 20, 2010. We continue to invite parties with hold harmless questions to contact Duke to discuss them.

III. "Hold Harmless" Issues Should Be Deferred

IMPA says that it "should be held harmless for any consequences associated with [DEO's] proposal for meeting resource adequacy requirements and Fixed Resource Requirements during the transition period."[55] But the "hold harmless" requirement is limited in nature and does not extend to resource adequacy. As the Commission has explained, the hold harmless obligation derives from the Midwest ISO Transmission Owners Agreement,[56] and there is no hold harmless obligation beyond that provided by that Agreement.[57] The governing provision provides, in its entirety:

> Users taking service which involves the withdrawing Owner and which involves transmission contracts executed before the Owner provided notice of its withdrawal shall continue to receive the same service for the remaining term of the contract at the same rates, terms, and conditions that would have been applicable if there were no withdrawal. The

54 *LG&E Withdrawal Order*, 114 FERC ¶ 61,282 at P 44. "[E]xisting" arrangements means those transmission contracts entered into prior to the date that DEO and DEK notified the Midwest ISO of their intent to withdraw, i.e., May 20, 2010. *Id.*; *see also Louisville Gas & Elec. Co.,order on reh'g*, 116 FERC ¶ 61,020 at P 24 (2006) ("*LG&E Rehearing Order*"). "[C]ontracts" include "grandfathered agreements, executed transmission service agreements under the [ASM Tariff] that cover specific transactions, or [any] confirmed reservation on the Midwest ISO Open-Access Same-time information system (OASIS) in existence as of the notice date." *LG&E Withdrawal Order*, 114 FERC ¶ 61,282 at P 46; *see also LG&E Rehearing Order*, 116 FERC ¶ 61,020 at P 24.

55 IMPA at 5 (footnote omitted).

56 The Agreement of Transmission Facilities Owners to Organize the Midwest Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation ("Midwest ISO Transmission Owners Agreement").

57 *LG&E Rehearing Order*, 116 FERC ¶ 61,020 at PP 7-13.

withdrawing Owner shall agree to continue providing service to such Users and shall receive no more in revenues for that service than if there had been no withdrawal by such Owner.[58]

IMPA seems to be arguing that it has transmission arrangements in the Midwest ISO that will be "disbanded" as a result of DEO's move to PJM, and from there draws a tenuous connection from this service to a desire to be able to "seamlessly deliver" its "MISO-area generation portfolio" to a network load (the City of Blanchester, Ohio) that will be in PJM once DEO moves.[59]

As we have explained,[60] hold harmless issues should not be addressed before DEO has proposed its new PJM zonal transmission rate, because until that proposal is made, there is no basis for a comparison between the old transmission rate and the new transmission rate. Even if it were appropriate to raise hold harmless issues now, IMPA has not made a threshold showing sufficient to warrant hold harmless treatment. It has not identified the "transmission contract"[61] from which its claim allegedly arises, much less offered the required proof that the contract was "existing" on May 20, 2010, the date that DEO gave notice of its withdrawal to the Midwest ISO.[62] IMPA also has not demonstrated that the remaining term of any such transmission contract extends

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58 Midwest ISO Transmission Owners Agreement, Art. Five § II.A.

59 IMPA at 5.

60 *See* Duke Initial Filing in Docket No. ER10-1562-000 at 4; Duke Answer in Docket No. ER10-1562-000, at 30-31; FRR Plan Filing at 4.

61 "[C]ontracts" include "grandfathered agreements, executed transmission service agreements under the [ASM Tariff] that cover specific transactions, or [any] confirmed reservation on the Midwest ISO Open-Access Same-time information system (OASIS) in existence as of the notice date." *LG&E Withdrawal Order*, 114 FERC ¶ 61,282 at P 46; *see also LG&E Rehearing Order*, 116 FERC ¶ 61,020 at P 24.

62 *LG&E Withdrawal Order*, 114 FERC ¶ 61,282 at P 44; *see also LG&E Rehearing Order*, 116 FERC ¶ 61,020 at P 24.

beyond the January 1, 2012 date of integration into PJM.[63] Perhaps most fundamentally, IMPA does not provide any evidence that its transmission contract has a provision entitling it, as a condition of its transmission service (which is the only thing protected by the hold harmless provision) to protection with respect to resource adequacy requirements.

We recognize that these are factual issues, and we are not suggesting that the Commission reject IMPA's claim. In fact, we ask that the Commission not reject IMPA's claim at this time, because we do not want IMPA to feel compelled to file an answer and try to turn this proceeding into something that it is not. Rather, we offer this response simply to illustrate that the record is insufficient to rule in IMPA's favor. As IMPA notes, we are in talks with IMPA, and IMPA expresses its optimism that a timely and amicable resolution can be reached.[64] The Commission recently deferred all hold harmless issues until the filing of the zonal transmission rate in similar circumstances with respect to FirstEnergy.[65]

However, should the Commission wish to provide IMPA (or other similarly situated entities, if there are any) with some comfort now on the topic of use of Midwest ISO capacity resources for reliability purposes in PJM, we refer the Commission to the discussion of capacity portability in the Duquesne withdrawal proceeding. There, the Commission recognized that as a result of their participation in the PJM RPM auction, Duquesne and other LSEs in its zone had procured out-of-zone capacity resources for

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63 *LG&E Withdrawal Order*, 114 FERC ¶ 61,282 at P 49.

64 IMPA at 4.

65 *American Transmission Systems, Inc.*, 129 FERC ¶ 61,249 at P 50 (2009).

the period after Duquesne planned to move to the Midwest ISO.[66] The Commission directed PJM "to support reasonable arrangements to permit Duquesne to utilize that capacity in satisfying its reliability obligations to the Midwest ISO" after Duquesne joined the Midwest ISO.[67] Subsequently, PJM filed portability agreements with respect to Duquesne and 13 other LSEs in the Duquesne zone.[68]

Because the Midwest ISO does not conduct a three-year forward auction, load in the DEO Midwest ISO footprint will only have an issue like IMPA's if the load has bilaterally contracted for capacity somewhere in the Midwest ISO outside of the DEO zone for the period after the RTO Realignment. So far only IMPA has raised this issue, and only with respect to its relatively small Blanchester load. So the issue does not appear to have anything approaching the scale that was at issue in the Duquesne situation. If it was possible for PJM to devise an appropriate portability arrangement for all the capacity committed to the Duquesne zone, it should be far simpler for the Midwest ISO (working with PJM as needed) to devise appropriate portability arrangements for IMPA and anyone similarly situated. Accordingly, we recommend that the Commission direct the Midwest ISO and PJM "to support reasonable arrangements to permit" any load with capacity under contract or owned for reliability purposes as of

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66 *See Duquesne*, *supra* n.1, 122 FERC ¶ 61,039 at P 93 (2008).

67 *Id.*

68 The Commission accepted PJM's filed portability agreements, subject to conditions. *See PJM Interconnection, L.L.C.*, 124 FERC ¶ 61,307 (2008). Duquesne sought rehearing. Subsequently, several parties to these and related docket proceedings submitted a settlement agreement resolving several omnibus issues, including that Duquesne would no longer seek to withdraw from PJM and join the Midwest ISO. The Commission approved the settlement agreement. *Duquesne Light Company*, 126 FERC ¶ 61,074 (2009), *reh'g denied*, 127 FERC ¶ 61,187 (2009).

the date that DEO gave notice of its intent to withdraw from the Midwest ISO (May 20, 2010) "*to utilize [such] capacity in satisfying its reliability obligations*" in PJM after DEO joins PJM.[69] We believe this will be particularly helpful to entities such as IMPA because we do not believe that the Midwest ISO Transmission Owners Agreement will be found, when the time comes, to hold them harmless with respects to resource adequacy requirements.

Motion for Leave to File Answer

Good cause exists to permit this answer because it will provide the Commission with information necessary to fully understand the issues raised by the protests and comments in this proceeding. The Commission may permit answers to protests pursuant to Rule 213(a)(2) for good cause shown if the answer "will not delay the proceeding, will assist the Commission in understanding the issues raised, and will insure a complete record upon which the Commission may act."[70] This answer meets these criteria and should be permitted as an appropriate exercise of the Commission's discretion.

Conclusion

For the reasons set forth above, and in the FRR Plan Filing, DEO and DEK request that the Commission grant the relief requested in the FRR Plan Filing.

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69 *Id.*

70 *PJM Interconnection, L.L.C.*, 105 FERC ¶ 61,312 at P 21 (2003); *PJM Interconnection, L.L.C.*, 104 FERC ¶ 61,154 at P 14 (2003); *PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,161 at P 13 (2003).

Respectfully Submitted,

/s/ Noel Symons

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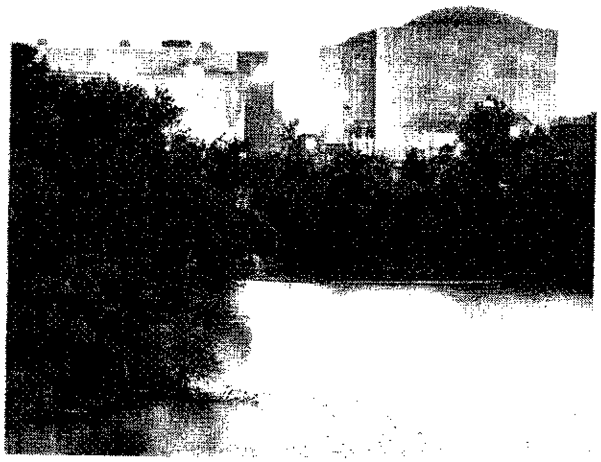
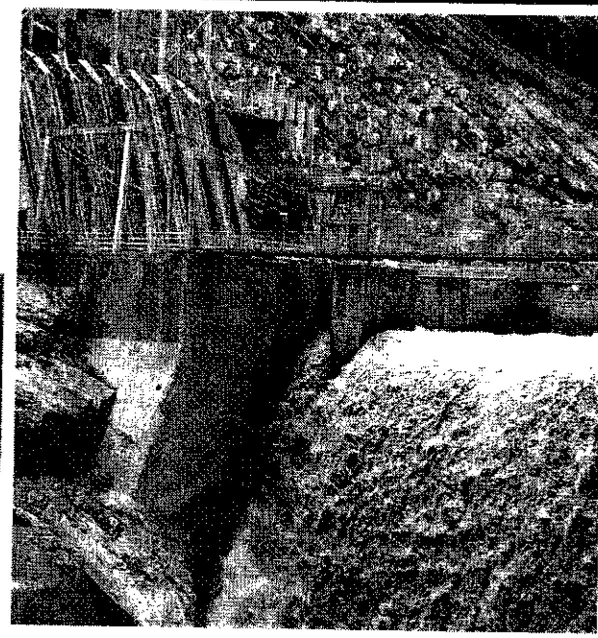
CERTIFICATE OF SERVICE

I hereby certify that I have on this day caused to be served a copy of the foregoing upon all parties on the service list in these proceedings in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

/s/ Andrea R. Kells
Andrea R. Kells

September 22, 2010





Duke Energy Investor and Analyst Meeting

February 28, 2013

Duke Energy.

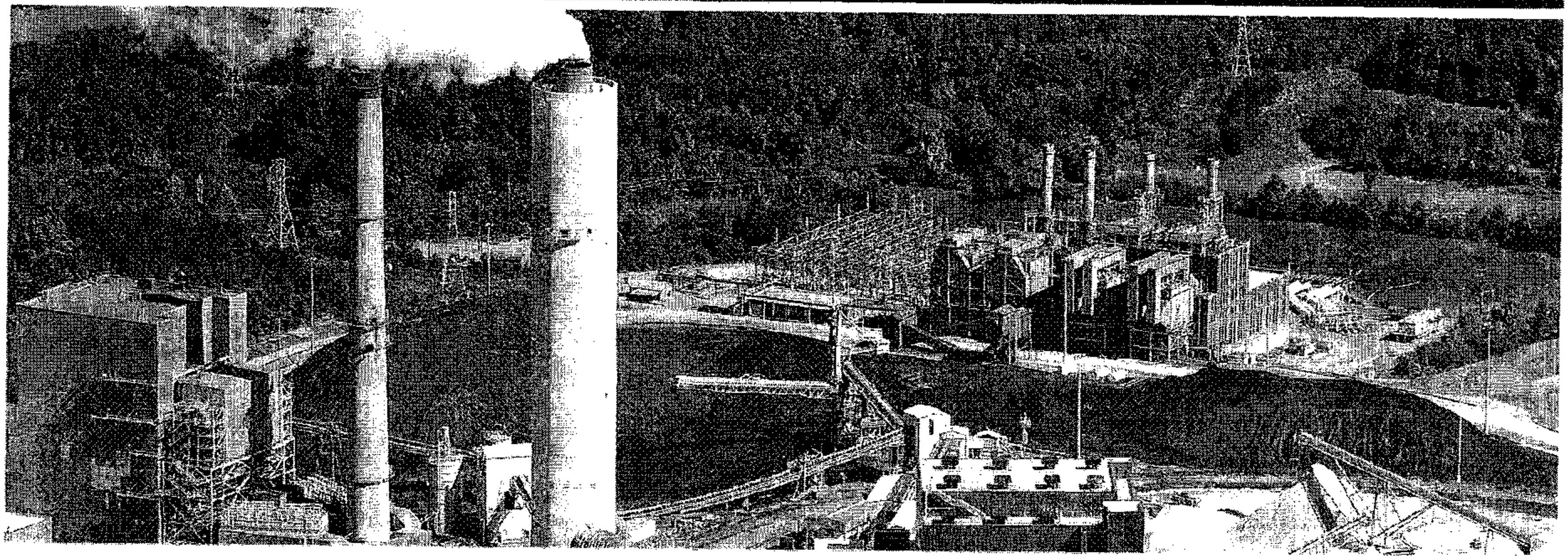
Today's agenda

Welcome & Safe Harbor	Bob Drennan, Vice President, Investor Relations
Strategic Overview	Jim Rogers, Chairman, President and CEO
Regulated Utilities Operations	Keith Trent, Executive VP and COO, Regulated Utilities
Nuclear Generation	Dhiaa Jamil, Executive VP and CNO
Regulated Utilities	Lloyd Yates, Executive VP, Regulated Utilities
Commercial Businesses	Marc Manly, Executive VP and President, Commercial Businesses
Financial Overview	Lynn Good, Executive VP and CFO
Discussion / Q&A	Panel
Closing Remarks	Jim Rogers

Duke Energy

3

Analyst Meeting



Regulated Utilities Operations

Keith Trent, Executive VP and COO, Regulated Utilities

Duke Energy

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Duke Energy steam facility data, cont. (As of 12/31/12)

Structure	Operating State	Jurisdiction	Steam Unit Facility	Owned Capacity – Summer Rating (MW)	Fuel Type	Current Cooling Method	Emissions Controls
Regulated	In Operation	DE Indiana	Cayuga	1,005	Coal	Once-Through	Scrubber, SCR Under Construction
Regulated	In Operation	DE Indiana	Gibson	2,822	Coal	Cooling Lake, No NPDES Permit	Scrubber and SCR
Regulated	In Operation (1)	DE Indiana	Wabash River	668	Coal	Once-Through	
Regulated	In Operation	DE Indiana	Gallagher 2&4	280	Coal	Once-Through	Baghouse
Regulated	In Operation	DE Indiana	Noblesville CC	310	Gas	Closed Cycle	
Regulated	In Operation	DE Kentucky	East Bend	414	Coal	Closed Cycle	Scrubber and SCR
Regulated	In Operation (1)	DE Kentucky	Miami Fort 6	163	Coal	Once-Through	
Non-Regulated	In Operation	DE Ohio	Conesville 4	312	Coal	Closed Cycle	Scrubber and SCR
Non-Regulated	In Operation	DE Ohio	Stuart 1-3	675	Coal	Once-Through	Scrubber and SCR
Non-Regulated	In Operation	DE Ohio	Stuart 4	225	Coal	Closed Cycle	Scrubber and SCR
Non-Regulated	In Operation	DE Ohio	Killen	198	Coal	Closed Cycle	Scrubber and SCR
Non-Regulated	In Operation (1)	DE Ohio	Beckjord	765	Coal	Once-Through	
Non-Regulated	In Operation	DE Ohio	Miami Fort 7-8	640	Coal	Closed Cycle	Scrubber and SCR
Non-Regulated	In Operation	DE Ohio	Zimmer	605	Coal	Closed Cycle	Scrubber and SCR
Non-Regulated	In Operation	Duke Energy	Fayette CC	633	Gas	Closed Cycle	SCR
Non-Regulated	In Operation	Duke Energy	Hanging Rock CC	1,262	Gas	Closed Cycle	SCR
Non-Regulated	In Operation	Duke Energy	Washington CC	639	Gas	Closed Cycle	SCR
Regulated	In Start-Up	DE Indiana	Edwardsport IGCC	618	Coal	Closed Cycle - No Intake	Selexol and SCR
Regulated	Under Construction	PE Carolinas	Sutton CC	625	Gas	Closed Cycle	SCR

(1) Potential retirements include Buck Units 5-6; Riverbend Units 4-7; DEC Lee Units 1-2; Sutton Units 1-3; Wabash River Units 2-5; Miami Fort Unit 6; and Beckjord Units 2-6. Reflects already completed retirements of Edwardsport 6-8 (160 MW), Buck 3-4 (113 MW), Cliffside 1-4 (198 MW), Dan River 1-3 (276 MW), Gallagher 1,3 (280 MW) per Consent Decree; Beckjord 1 (94 MW); Weatherspoon 1-3 (177 MW); PEC Lee 1-3 (391 MW); Bartow 1-3 (440 MW); Robinson 1 (177 MW); Cape Fear 5-6 (316 MW); and Crystal River 3 (789 MW). DEC Lee Unit 3 (170 MW) and Wabash River Unit 6 (320 MW) potential to be converted to gas or retired.

(2) Crystal River 1-2 (875 MW) under evaluation for MATS compliance; potential to be retired by 2015

Duke Energy

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Analyst Meeting

Financial Overview

Lynn Good, Executive VP and Chief Financial Officer

Duke Energy

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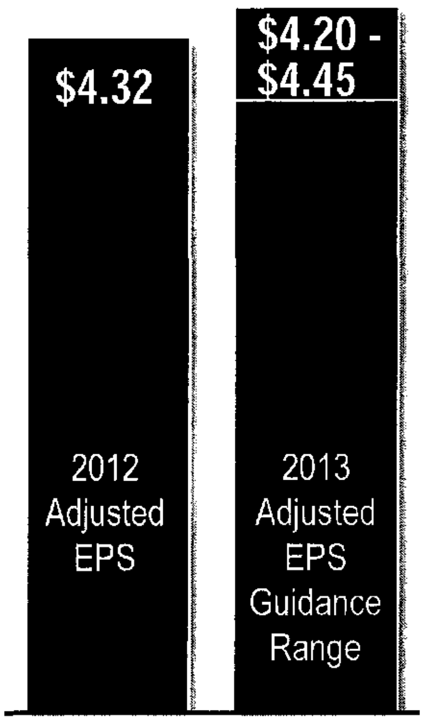
2013 key EPS drivers (1)



USFE&G

- ▲ Full year of Progress earnings
- ▲ Regulatory outcomes, net of recoverables
- ▲ Retail load growth of ~0.5%
- ▲ Growth in wholesale
- ▲ Normal weather
- ▲ Lower O&M, primarily due to merger savings
- ▼ CR3 retirement

INTERNATIONAL

- ▼ Unfavorable FX and hydrology in Brazil
- ▼ Lower commodity prices at NMC

COMMERCIAL POWER

- ▼ Lower PJM capacity revenues
- ▲ Ohio cost-based capacity filing

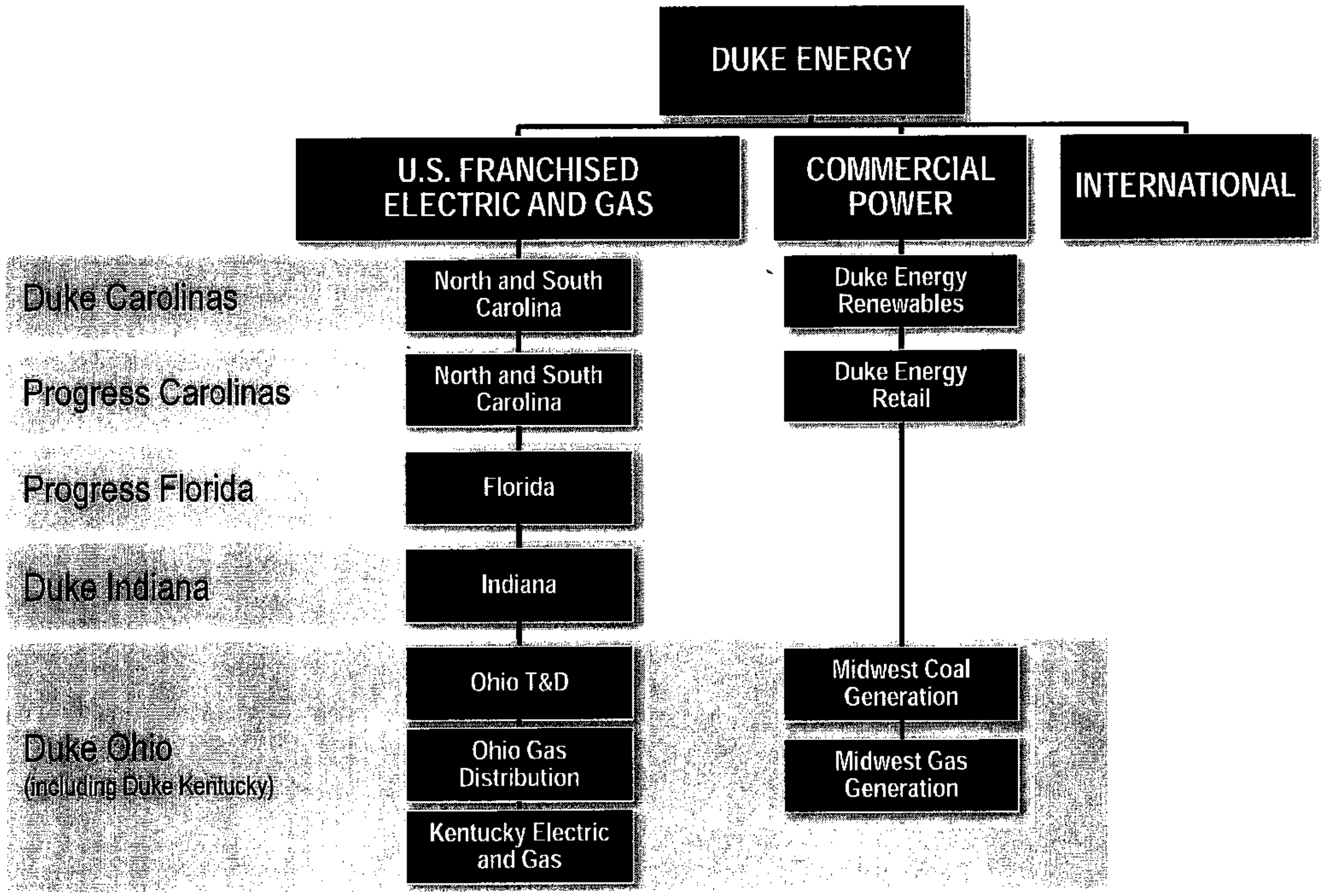
OTHER ITEMS

- ▼ Full year of interest expense on Progress HoldCo debt
- ▼ Share dilution
- ▼ Higher effective tax rate

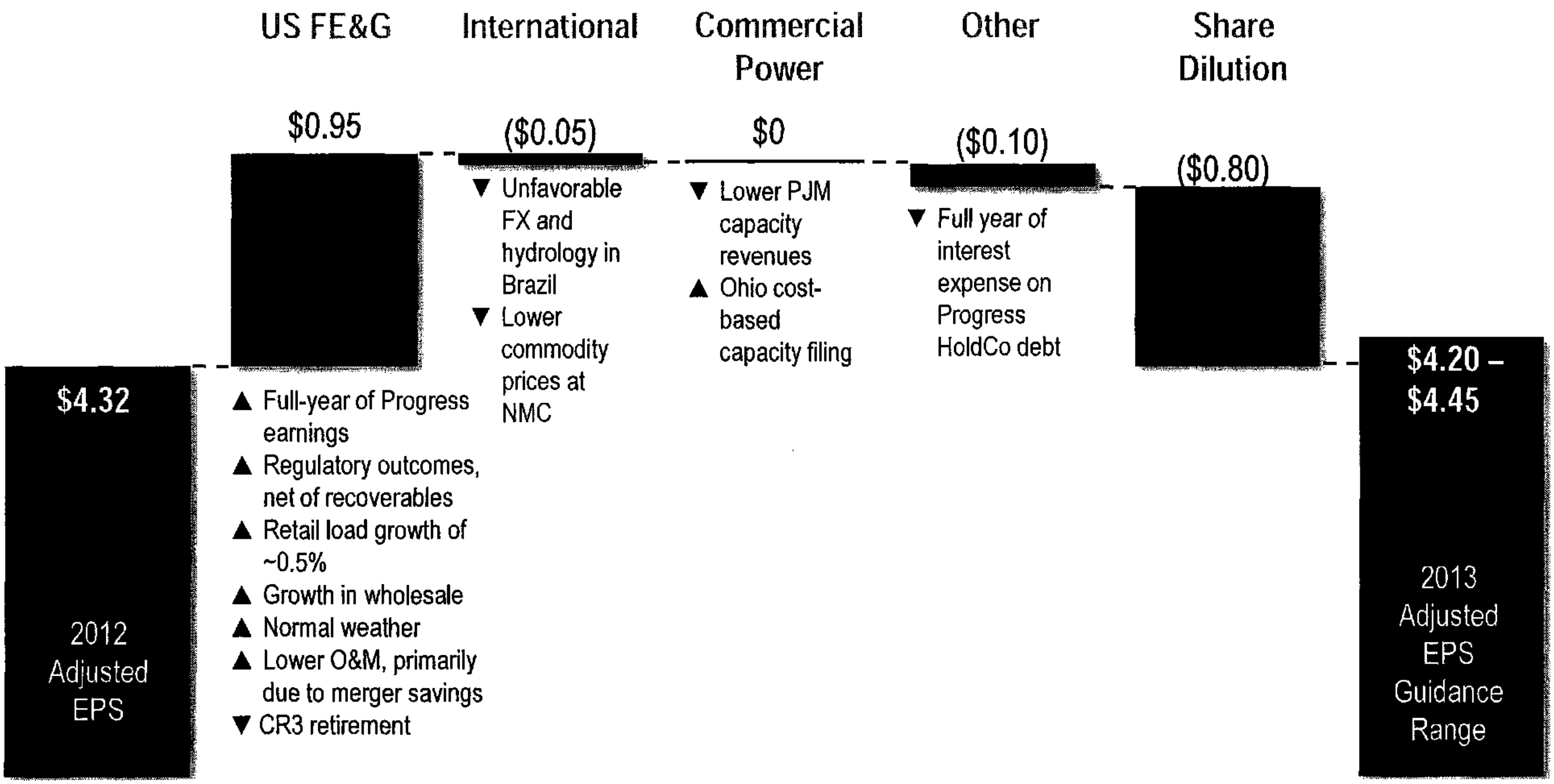
2013 guidance range covers variability due to the outcomes of pending rate cases as well as the Ohio state-based capacity request

(1) Based upon adjusted diluted EPS

Business segment structure



2013 adjusted earnings drivers



Note: Amounts not to scale; segment amounts are based upon midpoint of 2013 adjusted EPS guidance range of $4.20 - $4.45

Additional 2013 earnings guidance details

($ in millions)	2012 Actual	2013 Assumptions	MEMO: 2013 Interest Expense, Net	MEMO: 2013 Adj. Effective Tax Rate
Adjusted Segment Income (Expense) (1):				
USFE&G	$2,086	$2,755	$1,020	38%
International	$439	$405	$80	29%
Commercial Power	$93	$95	$70	(227%) (2)
Other	($135)	($205)	$410	---
Duke Energy Consolidated	$2,483	$3,050	$1,580	34 – 35%
Additional Consolidated Information:				
Interest Expense	$1,242	$1,580		
Adjusted Effective Tax Rate	31%	34 – 35%		
Debt AFUDC and Capitalized Interest	$177	$100		
AFUDC Equity	$301	$160		
Capital Expenditures	$5,950	$5,875-6,300		
Weighted-average shares outstanding	575 million	706 million		

(1) Based upon midpoint of 2013 adjusted EPS guidance range of $4.20 - $4.45
(2) The effective tax rate for Commercial Power includes tax benefits related to renewable projects

Credit ratings (as of February 22, 2013)

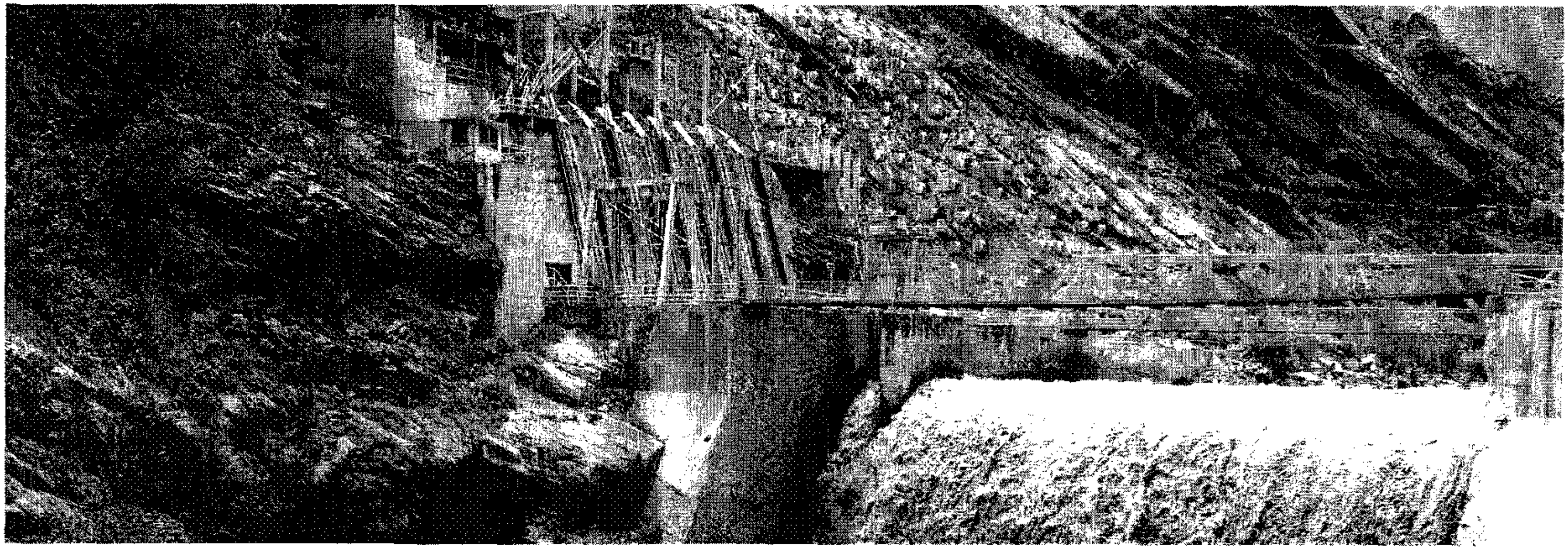
Holding Companies

	Fitch	Moody's	S&P
DUKE ENERGY	Stable	Stable	Negative
Corporate Credit / Issuer Rating	BBB+	Baa2	BBB+
Senior Unsecured Debt	BBB+	Baa2	BBB
Junior Subordinated Debt	BBB-	Baa3	BBB-
Commercial Paper	F-2	P-2	A-2
PROGRESS ENERGY	Stable	Stable	Negative
Senior Unsecured Debt	BBB	Baa2	BBB

Operating Companies

	Fitch	Moody's	S&P
DUKE CAROLINAS	Stable	Stable	Negative
Senior Secured Debt	A+	A1	A
Senior Unsecured Debt	A	A3	BBB+
PROGRESS CAROLINAS	Stable	Stable	Negative
Senior Secured Debt	A+	A1	A
Senior Unsecured Debt	A	A3	BBB+
PROGRESS FLORIDA	Negative	Stable	Negative
Senior Secured Debt	A	A2	A
Senior Unsecured Debt	A-	Baa1	BBB+
DUKE ENERGY INDIANA	Stable	Stable	Negative
Senior Secured Debt	A	A2	A
Senior Unsecured Debt	A-	Baa1	BBB+
DUKE ENERGY OHIO	Stable	Stable	Negative
Senior Secured Debt	A	A2	A
Senior Unsecured Debt	A-	Baa1	BBB+
DUKE ENERGY KENTUCKY	Stable	Stable	Negative
Senior Unsecured Debt	A-	Baa1	BBB+

Analyst Meeting

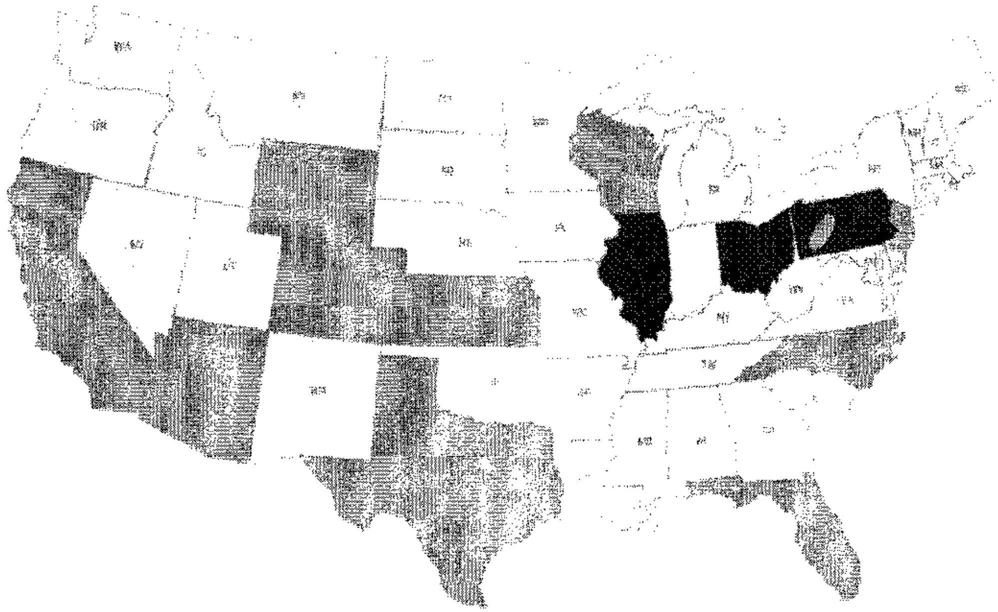


Commercial Businesses

Marc Manly, Executive VP and President, Commercial Businesses

Duke Energy

Commercial Power Segment – overview



Midwest Generation
Coal/Oil – 3,700 MW (1) Gas – 3,200 MW
Duke Energy Renewables
Wind – 1,600 MW Solar – 100 MW

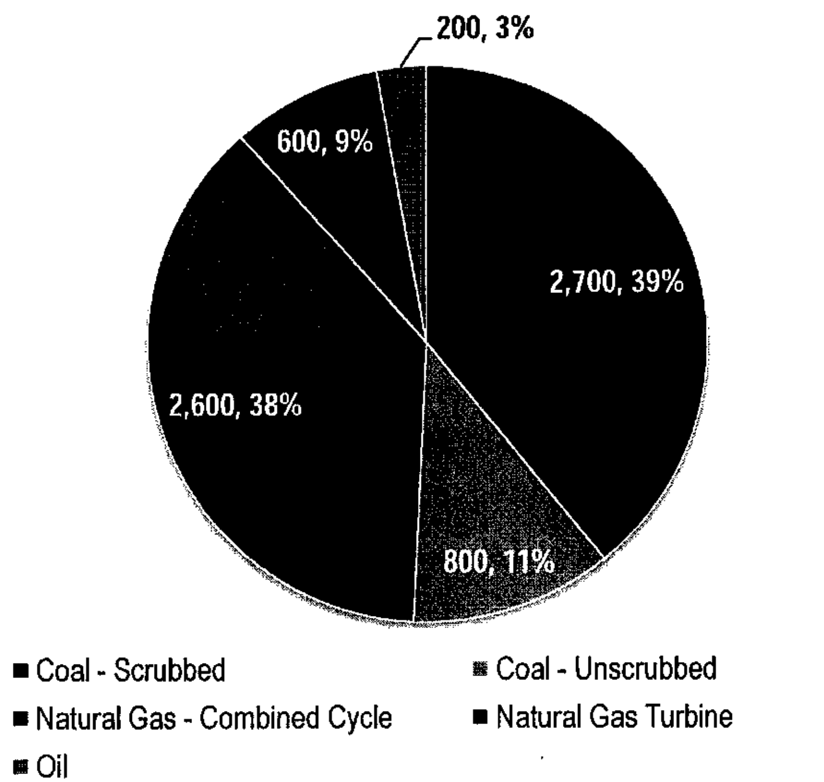
- **Midwest Generation** - mature merchant generation business in the PJM wholesale markets
- **Duke Energy Retail** – competitive retail electric service for customers in Ohio
- **Renewables** – long-term, contracted projects with attractive risk-adjusted returns
- **Commercial Transmission** – strategic projects to increase reliability, integrate renewables and relieve grid congestion. Joint ventures with American Transmission Company and AEP

(1) MWs include mothballed Beckjord units

Midwest Commercial Generation – overview

Portfolio Well Positioned for Market Changes and Environmental Regulations

Midwest Commercial Generation Mix (MW, %)



Coal-fired Generation

- Location provides fuel flexibility
- Energy margins squeezed by low natural gas prices
- Expect mercury rules could result in retirement of unscrubbed coal-fired generation by 2015

Natural Gas-fired Generation

- Well positioned in PJM to take advantage of Marcellus Shale gas
- Continued improvements in capacity factors and margins
- Gas turbines are purely a capacity market play

Midwest Commercial Generation strategies

Mitigate earnings pressures due to low PJM capacity prices and energy margins

Pursue Ohio cost-based capacity filing:

- State capacity mechanism was established in the AEP case for Fixed Resource Requirement (FRR) entities
- Provides Duke Energy Ohio's generation the ability to earn reasonable returns
- Hearings are scheduled for April 2013
- Outcome will inform our long-term strategic decisions on the Midwest Commercial Generation fleet

- Continue to develop the single fleet operating strategy and optimize capital investments
- Continue to execute hedging program to lock-in energy margins; essentially contracting the assets
- Continue to pursue a "fixed to variable" cost structure to provide more flexibility to respond to market conditions

Commercial Businesses strategy

- Follow a low-risk business model:
  - Highly contracted in DEI, and in Midwest Generation through financial hedging
  - Long-term PPA approach for Duke Energy Renewables
  - Diversification among different geographies, regulatory jurisdictions and fuel types
- Utilize the Commercial Businesses portfolio to support Duke Energy's long-term financial objectives
- Mitigate earnings pressures in Midwest Commercial Generation business:
  - Continue our successful costs control efforts
  - Successful outcome on the cost-based capacity filing in Ohio

Appendix – Midwest Commercial Generation

Midwest Generation guidance assumptions – 2013

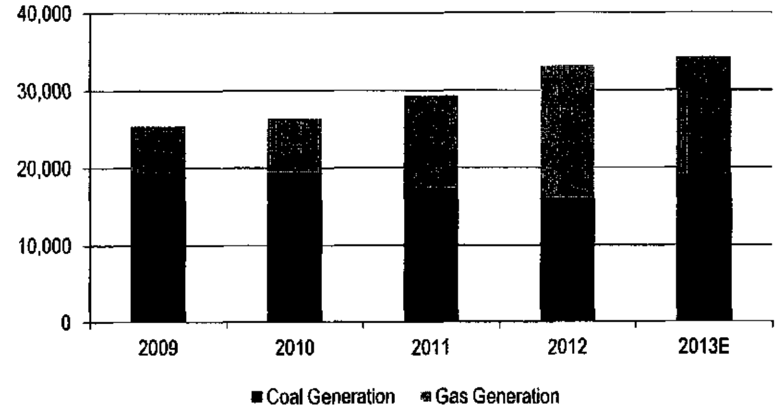
2013 Guidance Assumptions	
	Midwest Generation
[redacted]	[redacted]
PJM Capacity Revenues	$50 million
[redacted]	[redacted]
Assumed Economic Generation Volumes	~35 million MWh's
[redacted]	[redacted]

(1) Stability charge will be collected by Duke Energy Ohio

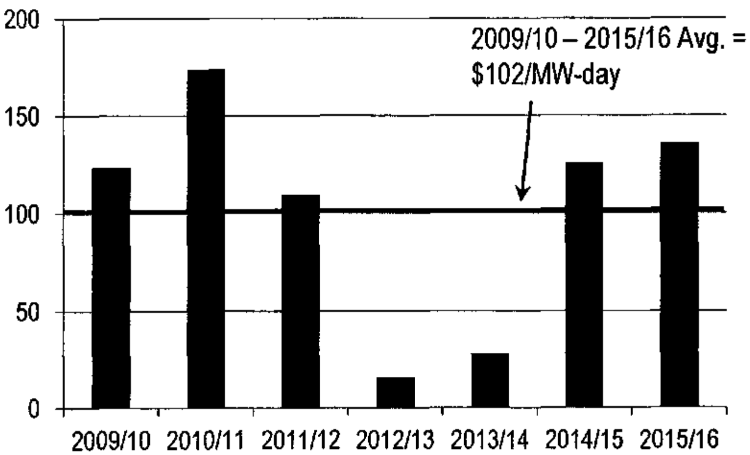
PJM CAPACITY PRICES

- 2012/13 and 2013/14 PJM capacity prices are at historical lows
- Historic average PJM capacity price (2009/10 - 2015/16) is around $102/MW-day
- Sensitivity to capacity price changes
  - Every $10/MW-day change in clearing price impacts Duke Energy capacity revenues by ~$20 million (or $0.02 EPS)

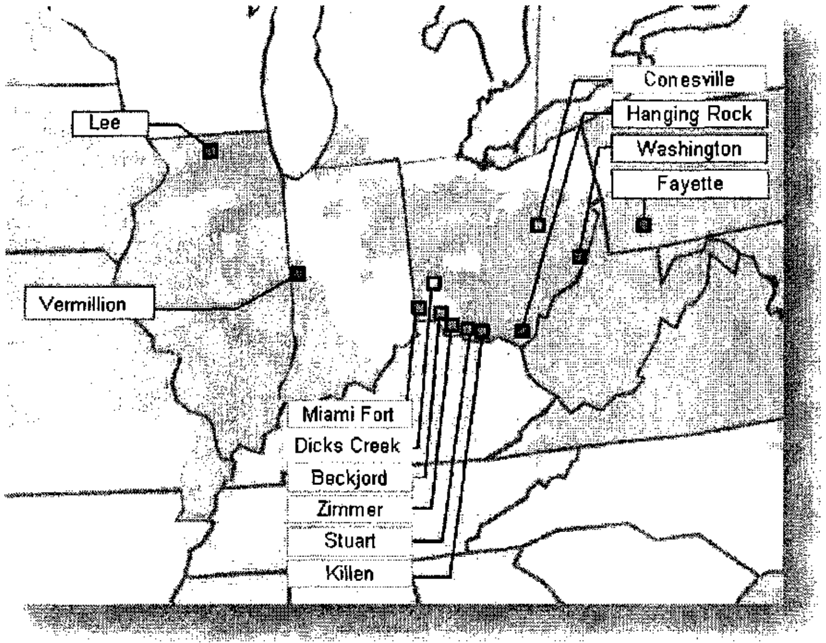
Generation Volumes (MM MWh's)



PJM Rest of Market ($/MW-Day)



Non-regulated Midwest Generation



Midwest Primarily Coal	
Coal/Oil	3,664 MW
Gas	136 MW
Midwest Gas-Fired	
Gas	3,025 MW
Total Fleet	6,825 MW

Midwest Primarily Coal		Midwest Gas Fired
Beckjord (PJM) - 953 MW [1] Type: 6 Coal Units, 4 CT Units Fuel: Coal, Oil Ownership: Unit 6 37.5%; 100% Location: New Richmond, OH In Service: 1952-1972	Stuart (PJM) - 900 MW Type: 4 Coal Units Fuel: Coal Ownership: 39% Operator: DP&L Location: Aberdeen, OH In Service: 1970-1974	Hanging Rock (PJM) - 1,226 MW Type: 2 Combined Cycle Units Fuel: Natural Gas Ownership: 100% Location: Ironton, OH In Service: 2003
Miami Fort (PJM) - 696 MW Type: 2 Coal Units, 4 CT Units Fuel: Coal, Oil Ownership: Units 7&8 64%; 100% Location: North Bend, OH In Service: 1949-1978	Zimmer (PJM) - 605 MW Type: 1 Coal Unit Fuel: Coal Ownership: 46.5% Location: Moscow, OH In Service: 1991	Lee (PJM) - 568 MW Type: 8 Simple Cycle units Fuel: Natural Gas Ownership: 100% Location: Dixon, IL In Service: 2001
Conesville (PJM) - 312 MW Type: 1 Coal Unit Fuel: Coal Ownership: 40% Operator: AEP Location: Coshocton, OH In Service: 1973	Killen (PJM) - 198 MW Type:1 Coal Unit Fuel: Coal Ownership: 33% Operator: DP&L Location: Wrightsville, OH In Service: 1982	Washington (PJM) - 617 MW Type: 1 Combined Cycle Unit Fuel: Natural Gas Ownership: 100% Location: Beverly, OH In Service: 2002
Dicks Creek (PJM) - 136 MW Type: 4 Simple Cycle Units Fuel: Natural Gas, #3NG/Oil Ownership: 100% Location: Middletown, OH In Service: 1965-1969		Fayette (PJM) - 614 MW Type: 1 Combined Cycle Unit Fuel: Natural Gas Ownership: 100% Location: Masontown, PA In Service: 2003

(1) MWs include mothballed Beckjord units

Duke Energy

Section 1: 10-K (FORM 10-K)

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

FOR ANNUAL AND TRANSITION REPORTS
PURSUANT TO SECTION 13 OR 15(d) OF
THE
SECURITIES EXCHANGE ACT OF 1943

(Mark One)
☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal period ended December 31, 2012 or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number	Exact name of registrants as specified in their charters, addresses of principal executive offices, telephone numbers and states of incorporation	IRS Employer Identification No.
1-32853	DUKE ENERGY CORPORATION 550 South Tryon Street Charlotte, NC 28202-1803 704-382-3853 State of Incorporation: Delaware	20-2777218
1-4928	DUKE ENERGY CAROLINAS, LLC 526 South Church Street Charlotte, NC 28202-1803 704-382-3853 State of Incorporation: North Carolina	56-0205520
1-15929	PROGRESS ENERGY, INC. 410 South Wilmington Street Raleigh, North Carolina 27601-1748 704-382-3853 State of Incorporation: North Carolina	56-2155481
1-3382	CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC. 410 South Wilmington Street Raleigh, North Carolina 27601-1748 704-382-3853 State of Incorporation: North Carolina	56-0165465
1-3274	FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC. 299 First Avenue North St. Petersburg, Florida 33701 704-382-3853 State of Incorporation: Florida	59-0247770
1-1232	DUKE ENERGY OHIO, INC. 139 East Fourth Street Cincinnati, OH 45202 704-382-3853 State of Incorporation: Ohio	31-0240030
1-3543	DUKE ENERGY INDIANA, INC. 1000 East Main Street Plainfield, IN 46168 704-382-3853 State of Incorporation: Indiana	35-0594457

SECURITIES REGISTERED PURSUANT TO SECTION 12(B) OF THE ACT:

Registrant	Title of each class	Name of each exchange on which registered
Duke Energy Corporation (Duke Energy)	Common Stock, $0.001 par value	New York Stock Exchange, Inc.
Duke Energy	5.125% Junior Subordinated Debentures due January 15, 2073	New York Stock Exchange, Inc.
Duke Energy Carolinas, LLC (Duke Energy Carolinas)	All of the registrant's limited liability company member interests are directly owned by Duke Energy.	
Progress Energy, Inc. (Progress Energy)	All of the registrant's common stock is directly owned by Duke Energy.	
Progress Energy Carolinas, Inc. (Progress Energy Carolinas)	All of the registrant's common stock is indirectly owned by Duke Energy.	
Progress Energy Florida, Inc. (Progress Energy Florida)	All of the registrant's common stock is indirectly owned by Duke Energy.	
Duke Energy Ohio, Inc. (Duke Energy Ohio)	All of the registrant's common stock is indirectly owned by Duke Energy.	
Duke Energy Indiana, Inc. (Duke Energy Indiana)	All of the registrant's common stock is indirectly owned by Duke Energy.	

EXHIBIT
PENGAD 800-631-6989
OEG-3

ITEM 1. BUSINESS

DUKE ENERGY

General. Duke Energy Corporation (collectively with its subsidiaries, Duke Energy) is an energy company headquartered in Charlotte, North Carolina. Duke Energy operates in the U.S. primarily through its direct and indirect wholly owned subsidiaries, Duke Energy Carolinas, LLC (Duke Energy Carolinas), Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. (Progress Energy Carolinas), Florida Power Corporation d/b/a Progress Energy Florida, Inc. (Progress Energy Florida), Duke Energy Ohio, Inc. (Duke Energy Ohio), and Duke Energy Indiana, Inc. (Duke Energy Indiana), as well as in Latin America through Duke Energy International, LLC (DEI). When discussing Duke Energy's consolidated financial information, it necessarily includes the results of its six separate subsidiary registrants, Duke Energy Carolinas, Progress Energy, Inc. (Progress Energy), Progress Energy Carolinas, Progress Energy Florida, Duke Energy Ohio, and Duke Energy Indiana (collectively referred to as the Subsidiary Registrants), which, along with Duke Energy, are collectively referred to as the Duke Energy Registrants. The financial information for Progress Energy, Progress Energy Carolinas and Progress Energy Florida includes results after July 2, 2012.

Duke Energy is a Delaware corporation. Its principal executive offices are located at 550 South Tryon Street, Charlotte, North Carolina 28202-1803. Duke Energy Carolinas is a North Carolina limited liability company. Its principal executive offices are located at 526 South Church Street, Charlotte, North Carolina 28202-1803. Progress Energy and Progress Energy Carolinas are North Carolina corporations. Their principal executive offices are located at 410 South Wilmington Street, Raleigh, North Carolina 27601-1748. Progress Energy Florida is a Florida corporation. Its principal executive offices are located at 299 First Avenue North, St. Petersburg, Florida 33701. Duke Energy Ohio is an Ohio corporation. Its principal executive offices are located at 139 East Fourth Street, Cincinnati, Ohio 45202. Duke Energy Indiana is an Indiana corporation. Its principal executive offices are located at 1000 East Main Street, Plainfield, Indiana 46168.

The telephone number for the Duke Energy Registrants is 704-382-3853. The Duke Energy Registrants electronically file reports with the Securities and Exchange Commission (SEC), including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxies and amendments to such reports.

The public may read and copy any materials that the Duke Energy Registrants file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov. Additionally, information about the Duke Energy Registrants, including its reports filed with the SEC, is available through Duke Energy's website at http://www.duke-energy.com. Such reports are accessible at no charge through Duke Energy's website and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC.

Merger with Progress Energy. On July 2, 2012, Duke Energy completed the merger contemplated by the Agreement and Plan of Merger (Merger Agreement), among Duke Energy, Diamond Acquisition Corporation, a North Carolina corporation and Duke Energy's wholly owned subsidiary (Merger Sub) and Progress Energy, Inc. (Progress Energy), a North Carolina corporation engaged in the regulated utility business of generation, transmission and distribution and sale of electricity in portions of North Carolina, South Carolina and Florida. As a result of the merger, Merger Sub was merged into Progress Energy and Progress Energy became a wholly owned subsidiary of Duke Energy.

The merger between Duke Energy and Progress Energy provides increased scale and diversity with potentially enhanced access to capital over the long term and a greater ability to undertake the significant construction programs necessary to respond to increasing environmental regulation, plant retirements and customer demand growth. Duke Energy's business risk profile is expected to improve over time due to the increased proportion of the business that is regulated. Additionally, cost savings, efficiencies and other benefits are expected from the combined operations.

Immediately preceding the merger, Duke Energy completed a one-for-three reverse stock split with respect to the issued and outstanding shares of Duke Energy common stock. The shareholders of Duke Energy approved the reverse stock split at Duke Energy's special meeting of shareholders held on August 23, 2011. All share and per share amounts presented within the Form 10-K reflect the impact of the one-for-three reverse stock split.

Progress Energy's shareholders received 0.87083 shares of Duke Energy common stock in exchange for each share of Progress Energy common stock outstanding as of July 2, 2012. Generally, all outstanding Progress Energy equity-based compensation awards were converted into Duke Energy equity-based compensation awards using the same ratio. The merger was structured as a tax-free exchange of shares.

For additional information on the details of this transaction including regulatory conditions and accounting implications, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 2 to the Consolidated Financial Statements, "Acquisitions and Dispositions of Businesses and Sales of Other Assets."

Duke Energy Business Segments. Duke Energy conducts its operations in the following business segments, all of which are considered reportable segments under the applicable accounting rules: U.S. Franchised Electric and Gas (USFE&G), Commercial Power and International Energy. The remainder of Duke Energy's operations are presented as Other. Duke Energy's chief operating decision maker regularly reviews financial information about each of these business segments in deciding how to allocate resources and evaluate performance. For additional information on each of these business segments, including financial and geographic information about each reportable business segment, see Note 3 to the Consolidated Financial Statements, "Business Segments."

The following sections describe the business and operations of each of Duke Energy's reportable business segments, as well as Other. (For more information on the operating outlook of Duke Energy and its reportable segments, see "Management's Discussion and Analysis of Financial Condition and Results of Operations, Introduction — Executive Overview and Economic Factors for Duke Energy's Business."

U.S. FRANCHISED ELECTRIC AND GAS

U.S. Franchised Electric and Gas (USFE&G) generates, transmits, distributes and sells electricity in most portions of North Carolina, northern South Carolina, central, north central and southern Indiana, west central Florida, and northern Kentucky. USFE&G also transmits, distributes and sells electricity in southwestern Ohio. Additionally, USFE&G transports and sells natural gas in southwestern Ohio and northern Kentucky. It conducts operations primarily through Duke Energy Carolinas, Progress Energy Carolinas, Progress Energy Florida, Duke Energy Indiana, and the regulated transmission and distribution operations of Duke Energy Ohio (Duke Energy Indiana and Duke Energy Ohio are collectively referred to as Duke Energy Midwest). These electric and gas operations are subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC), the North Carolina Utilities Commission (NCUC), the Public Service Commission of South Carolina (PSCSC), the Florida Public Service Commission (FPSC), the Public Utilities Commission of Ohio (PUCO), the Indiana Utility Regulatory Commission (IURC), and the Kentucky Public Service Commission (KPSC). The substantial majority of USFE&G's operations are regulated and, accordingly, these operations qualify for regulatory accounting treatment.

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dollars. This estimate includes Duke Energy Carolinas' ownership interest in the jointly owned nuclear reactors. The other joint owners of the jointly owned nuclear reactors are responsible for decommissioning costs related to their ownership interests in the station. The balance of Duke Energy Carolinas' external Nuclear Decommissioning Trust Funds (NDTF) was $2,354 million as of December 31, 2012 and $2,060 million as of December 31, 2011.

Progress Energy Carolinas' most recent site-specific nuclear decommissioning cost studies were completed in 2009 and showed total estimated nuclear decommissioning costs, including the cost to decommission plant components not subject to radioactive contamination of $3.0 billion in 2009 dollars. This estimate includes Progress Energy Carolinas' ownership interest in the jointly owned nuclear reactors. The other joint owners of the jointly owned nuclear reactors are responsible for decommissioning costs related to their ownership interests in the station. The balance of Progress Energy Carolinas' external NDTF was $1,259 million as of December 31, 2012 and $1,086 million as of December 31, 2011.

Progress Energy Florida's most recent site-specific nuclear decommissioning cost studies were completed in 2008. In the Progress Energy Florida 2009 rate case, the FPSC deferred review of the 2008 nuclear decommissioning study until 2010. While Progress Energy Florida was not required to prepare a new site-specific nuclear decommissioning cost study, it was required to update its 2008 study by incorporating the most currently-available escalation rates. This update was filed with the FPSC in December 2010. The FPSC approved this study on April 30, 2012 and showed total estimated nuclear decommissioning costs based on prompt dismantlement at the end of Crystal River Unit 3's useful life, including the cost to decommission plant components not subject to radioactive contamination of $751 million in 2008 dollars. This estimate includes Progress Energy Florida's ownership interest in the jointly owned nuclear reactor. The other joint owners of the jointly owned nuclear reactor are responsible for decommissioning costs related to their ownership interests in the station. With the decision in early 2013 to retire Crystal River Unit 3, as discussed below, it is anticipated that a delayed dismantlement approach to decommissioning, referred to as SAFSTOR, will be submitted to the NRC for approval. This decommissioning approach is currently utilized at a number of retired domestic nuclear power plants and is one of three generally accepted approaches to decommissioning required by the NRC. Once an updated site specific decommissioning study is completed it will be filed with the FPSC. As part of the evaluation of repairing Crystal River Unit 3, initial estimates of the cost to decommission the plant under the SAFSTOR option were developed, including components not subject to radioactive contamination, of $989 million in 2011 dollars. The balance of the external NDTF was $629 million as of December 31, 2012 and $559 million as of December 31, 2011.

The NCUC, FPSC and the PSCSC have allowed USFE&G's regulated utilities to recover estimated decommissioning costs through retail rates over the expected remaining service periods of their nuclear stations. USFE&G believes that the decommissioning costs being recovered through rates, when coupled with the existing fund balance and expected fund earnings, will be sufficient to provide for the cost of future decommissioning. See Note 9 to the Consolidated Financial Statements, "Asset Retirement Obligations," for more information.

The Nuclear Waste Policy Act of 1982 (as amended) provides the framework for development by the federal government of interim storage and permanent disposal facilities for high-level radioactive waste materials. The Nuclear Waste Policy Act of 1982 promotes increased usage of interim storage of spent nuclear fuel at existing nuclear plants. USFE&G will continue to maximize the use of spent fuel storage capability within its own facilities for as long as feasible.

Under federal law, the U.S. Department of Energy (DOE) is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. Progress Energy Carolinas and Progress Energy Florida have contracts with the DOE for the future storage and disposal of our spent nuclear fuel. Delays have occurred in the DOE's proposed permanent repository to be located at Yucca Mountain, Nevada. See Note 5 to the Consolidated Financial Statements, "Commitments and Contingencies," for information about complaints filed by Progress Energy Carolinas and Progress Energy Florida in the United States Court of Federal Claims against the DOE for its failure to fulfill its contractual obligation to receive spent fuel from nuclear plants. Failure to open Yucca Mountain or another facility would leave the DOE open to further claims by utilities.

Until the DOE begins to accept the spent nuclear fuel, Progress Energy Carolinas and Progress Energy Florida will continue to safely manage their spent nuclear fuel. With certain modifications and additional approvals by the NRC, including the installation and/or expansion of on-site dry cask storage facilities at Robinson Nuclear Station (Robinson), Brunswick Nuclear Station (Brunswick) and Crystal River Unit 3, the Progress Energy Carolinas and Progress Energy Florida's spent nuclear fuel storage facilities will be sufficient to provide storage space for spent fuel generated by their respective systems through the expiration of the operating licenses, including any license renewals, for their nuclear generating units. Harris has sufficient storage capacity in its spent fuel pools through the expiration of its renewed operating license.

Regulation

State

The NCUC, the PSCSC, the FPSC, the PUCO, the IURC and the KPSC (collectively, the state utility commissions) approve rates for retail electric service within their respective states. In addition, the PUCO and the KPSC approve rates for retail gas distribution service within their respective states. The state utility commissions, except for the PUCO, also have authority over the construction and operation of USFE&G's generating facilities. Certificates of Public Convenience and Necessity (CPCN) issued by the state utility commissions, as applicable, authorize USFE&G to construct and operate its electric facilities, and to sell electricity to retail and wholesale customers. Prior approval from the relevant state utility commission is required for USFE&G's regulated operating companies to issue securities. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus earn a reasonable rate of return on its invested capital, including equity.

Each of the state utility commissions allows recovery of certain costs through various cost-recovery clauses, to the extent the respective commission determines in periodic hearings that such costs, including any past over or under-recovered costs, are prudent. The clauses are in addition to approved base rates. USFE&G's regulated utilities generally do not earn a return on the recovery of eligible operating expenses under such clauses; however, in certain jurisdictions, they may earn a return on under-recovered costs. Additionally, the commissions may authorize a return for specified investments for energy efficiency and conservation, capacity costs, environmental compliance and utility plant.

Fuel, fuel-related costs and certain purchased power costs are eligible for recovery by USFE&G's regulated utilities. USFE&G uses coal, oil, hydroelectric, natural gas and nuclear power to generate electricity, thereby maintaining a diverse fuel mix that helps mitigate the impact of cost increases in any one fuel. Due to the associated regulatory treatment and the method allowed for recovery, changes in fuel costs from year to year have no material impact on operating results of USFE&G, unless a commission finds a portion of such costs to have been imprudent. However, delays between the expenditure for fuel costs and recovery from ratepayers can adversely impact the timing of cash flow of USFE&G. Progress Energy Florida is obligated to notify the FPSC and permitted to file for a midcourse change to the fuel factor between annual fuel hearings in the event its estimated over- or under-recovery of fuel costs meets or exceeds a threshold of ten percent of estimated total retail fuel revenues and, accordingly, has the ability to mitigate the cash flow impacts due to the timing of recovery of fuel and purchased power costs.

The following is a summary of pending retail base rate case proceedings for each of USFE&G's regulated utilities.

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Duke Energy Carolinas 2013 North Carolina Rate Case. On February 4, 2013, Duke Energy Carolinas filed an application with the NCUC for an increase in base rates of approximately $446 million, or an average 9.7% increase in revenues. The request for increase is based upon an 11.25% return on equity and a capital structure of 53% equity and 47% long-term debt. The rate increase is designed primarily to recover the cost of plant modernization, environmental compliance and the capital additions.

Duke Energy Carolinas expects revised rates, if approved, to go into effect late third quarter of 2013.

Progress Energy Carolinas 2012 North Carolina Rate Case. On October 12, 2012, Progress Energy Carolinas filed an application with the NCUC for an increase in base rates of approximately $387 million, or an average 12% increase in revenues. The request for increase is based upon an 11.25% return on equity and a capital structure of 55% equity and 45% long-term debt. The rate increase is designed primarily to recover the cost of plant modernization and other capital investments in generation, transmission and distribution systems, as well as increased expenditures for nuclear plants and personnel, vegetation management and other operating costs. The rate case includes a corresponding decrease in Progress Energy Carolinas' energy efficiency and demand side management rider, resulting in a net requested increase of $359 million, or 11% increase in retail revenues.

On February 25, 2013, the North Carolina Public Staff filed with the NCUC a Notice of Settlement in Principle (Settlement Notice). Pursuant to the Settlement Notice between Progress Energy Carolinas and the Public Staff, the parties have agreed to a two year step-in to a total agreed upon net rate increase, with the first year providing for a $151 million, or 4.7% average increase in rates, and the second year providing for rates to be increased by an additional $31 million, or 1.0% average increase in rates. This second year increase is a result of Progress Energy Carolinas agreeing to delay collection of financing costs on the construction work in progress for the Sutton combined cycle natural gas plant for one year. The Settlement Notice is based upon a return on equity of 10.2% and a 53% equity component of the capital structure.

Once filed, the actual settlement agreement will be subject to approval by the NCUC. Progress Energy Carolinas expects revised rates, if approved, to go into effect June 1, 2013.

Duke Energy Ohio 2012 Electric Rate Case. On July 9, 2012, Duke Energy Ohio filed an application with the PUCO for an increase in electric distribution rates of approximately $87 million. On average, total electric rates would increase approximately 5.1% under the filing. The rate increase is designed to recover the cost of investments in projects to improve reliability for customers and upgrades to the distribution system. Pursuant to a stipulation in another case, Duke Energy Ohio will continue recovering its costs associated with grid modernization in a separate rider.

Duke Energy Ohio expects revised rates, if approved, to go into effect in the first half of 2013.

Duke Energy Ohio 2012 Natural Gas Rate Case. On July 9, 2012, Duke Energy Ohio filed an application with the PUCO for an increase in natural gas distribution rates of approximately $45 million. On average, total natural gas rates would increase approximately 6.6% under the filing. The rate increase is designed to recover the cost of upgrades to the distribution system, as well as environmental cleanup of manufactured gas plant sites. In addition to the recovery of costs associated with the manufactured gas plants, the rate request includes a proposal for an accelerated service line replacement program and a new rider to recover the associated incremental cost. The filing also requests that the PUCO renew the rider recovery of Duke Energy Ohio's accelerated main replacement program and grid modernization program.

On January 4, 2013, the PUCO Staff filed a staff report recommending that Duke Energy Ohio only be allowed to recover costs related to manufactured gas plant (MGP) sites which are currently used and useful in the provision of natural gas distribution service. Duke Energy Ohio filed its objection to the staff report on February 4, 2013.

Duke Energy Ohio expects revised rates, if approved, to go into effect in the first half of 2013.

The following is a summary of recently resolved or settled retail base rate case proceedings for each of USFE&G's regulated utilities.

Progress Energy Florida 2012 FPSC Settlement. On February 22, 2012, the FPSC approved a comprehensive settlement agreement among Progress Energy Florida, the Florida Office of Public Counsel and other consumer advocates. The 2012 FPSC Settlement Agreement will continue through the last billing cycle of December 2016. The agreement addresses three principal matters: (i) Progress Energy Florida's proposed Levy Nuclear Project cost recovery, (ii) the Crystal River Unit 3 delamination prudence review then pending before the FPSC, and (iii) certain customer rate matters. See Note 4 to the Consolidated Financial Statements, "Regulatory Matters – Rate Related Information," for additional provisions of the 2012 settlement agreement.

Duke Energy Carolinas 2011 North Carolina Rate Case. On January 27, 2012, the NCUC approved a settlement agreement between Duke Energy Carolinas and the North Carolina Utilities Public Staff (Public Staff). The terms of the agreement include an average 7.2% increase in retail revenues, or approximately $309 million annually beginning in February 2012. The agreement includes a 10.5% return on equity and a capital structure of 53% equity and 47% long-term debt.

On March 28, 2012, the North Carolina Attorney General filed a notice of appeal with the NCUC challenging the rate of return approved in the agreement. On April 17, 2012, the NCUC denied Duke Energy Carolinas' request to dismiss the notice of appeal. Briefs were filed on August 22, 2012 by the North Carolina Attorney General and the American Association of Retired Persons (AARP) with the North Carolina Supreme Court, which is hearing the appeal. Duke Energy Carolinas filed a motion to dismiss the appeal on August 31, 2012 and the North Carolina Attorney General filed a response to that motion on September 13, 2012. Briefs by the appellees, Duke Energy Carolinas and the Public Staff, were filed on September 21, 2012. The North Carolina Supreme Court denied Duke Energy Carolinas' motion to dismiss on procedural grounds and set the matter for oral arguments on November 13, 2012. Duke Energy Carolinas is awaiting an order.

Duke Energy Carolinas 2011 South Carolina Rate Case. On January 25, 2012, the PSCSC approved a settlement agreement between Duke Energy Carolinas and the ORS, Wal-Mart Stores East, LP, and Sam's East, Inc. The Commission of Public Works for the city of Spartanburg, South Carolina and the Spartanburg Sanitary Sewer District were not parties to the agreement; however, they did not object to the agreement. The terms of the agreement include an average 5.98% increase in retail and commercial revenues, or approximately $93 million annually beginning February 6, 2012. The agreement includes a 10.5% return on equity, a capital structure of 53% equity and 47% long-term debt.

Duke Energy Ohio Standard Service Offer (SSO). The PUCO approved Duke Energy Ohio's current Electric Security Plan (ESP) on November 22, 2011. The ESP effectively separates the generation of electricity from Duke Energy Ohio's retail load obligation and requires Duke Energy Ohio to transfer its generation assets to a nonregulated affiliate on or before December 31, 2014. The ESP includes competitive auctions for electricity supply whereby the energy price is recovered from retail customers. As a result, Duke Energy Ohio now earns retail margin on the transmission and distribution of electricity only and not on the cost of the underlying energy. New rates for Duke Energy Ohio went into effect for SSO customers on January 1, 2012. The ESP also includes a provision for a non-bypassable stability charge of $110 million per year to be collected from January 1, 2012 through December 31, 2014

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Hydroelectric Generating Facilities. All but one of USFE&G's hydroelectric generating facilities are licensed by the FERC under Part I of the Federal Power Act. The FERC has jurisdiction to issue new hydroelectric operating licenses when the existing license expires. The 13 hydroelectric stations of the Catawba-Wateree Project are in the late stages of the FERC relicensing process. These stations continue to operate under annual extensions of the current FERC license, which expired in 2008, until the FERC issues a new license, which is currently projected to be issued by mid-2013. Relicensing is now under way for two hydroelectric stations comprising the Keowee-Toxaway Project. The current Keowee-Toxaway Project license does not expire until 2016 and the project will continue to operate under the current license until the new license is issued. The Bad Creek Project license will expire in 2028, the Gaston Shoals Project and Ninety Nine Islands Project licenses will expire in 2036 and the Queens Creek Project which will expire in 2023. All other hydroelectric stations are operating under current operating licenses, including ten hydroelectric stations in the East Fork, West Fork, Nantahala, Bryson, Mission, Franklin projects, and the Markland Project (in Indiana) for which new licenses were issued in 2010 through 2012. Duke Energy requested and the FERC approved a license surrender for the Dillsboro project. Duke Energy Carolinas has removed the Dillsboro Project dam and powerhouse as part of multi-project and multi-stakeholder agreements and Duke Energy Carolinas is continuing with stream restoration and post-removal monitoring as requested by FERC's license surrender order.

Progress Energy Carolinas has three hydroelectric generating plants licensed by the FERC: Walters, Tillery and Blewett. Progress Energy Carolinas also owns the Marshall Plant, which has a license exemption. The total summer generating capacity for all four units is 225 MW. Progress Energy Carolinas submitted an application to relicense its Tillery and Blewett plants for 50 years and anticipates a decision by the FERC in 2013. The Walters Plant license will expire in 2034.

Other Matters. USFE&G is subject to the jurisdiction of the U.S. Environmental Protection Agency (EPA) and state and local environmental agencies. For a discussion of environmental regulation, see "Environmental Matters" in this section.

See "Other Issues" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion about potential Global Climate Change legislation and other EPA regulations under development and the potential impacts such legislation and regulation could have on Duke Energy's operations.

COMMERCIAL POWER

Commercial Power owns, operates and manages power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants as well as other contractual positions. Commercial Power's generation operations, excluding renewable energy generation assets, consist primarily of coal-fired and gas-fired nonregulated generation assets which are dispatched into wholesale markets. These assets are comprised of 6,825 net MW of power generation primarily located in the Midwestern U.S. The asset portfolio has a diversified fuel mix with baseload and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units. The coal-fired generation assets were dedicated under the Duke Energy Ohio Electric Security Plan (ESP) through December 31, 2011. As discussed in the USFE&G section above, the new ESP effectively separates the generation of electricity from Duke Energy Ohio's retail load obligation as of January 1, 2012. As a result, As a result, the energy from Duke Energy Ohio's coal-fired generation assets no longer serve retail load customers or receive negotiated pricing under the ESP. Effective January 1, 2012, Duke Energy Ohio completed its Regional Transmission Organization (RTO) realignment to PJM and operates as a Fixed Resource Requirement (FRR) entity through May 31, 2015. As an FRR entity, Duke Energy Ohio is obligated to self supply capacity for the Duke Energy Ohio load zone. The generation assets began selling all of their electricity into wholesale markets in January 2012 and currently receive wholesale energy margins and capacity revenues from PJM at market rates. Commercial Power has economically hedged its forecasted coal-fired generation and a significant portion of its forecasted gas-fired generation for 2013. Capacity revenues are 100% contracted in PJM through May 2016.

For information on Commercial Power's generation facilities, see "Commercial Power" in Item 2, "Properties"

Commercial Power also has a retail sales subsidiary, Duke Energy Retail Sales, LLC (Duke Energy Retail), which is certified by the PUCO as a Competitive Retail Electric Supplier (CRES) provider in Ohio. Duke Energy Retail serves retail electric and gas customers in southwest, west central and northern Ohio with energy and other energy services at competitive rates.

Through Duke Energy Generation Services, Inc. (DEGS), Commercial Power engages in the development, construction and operation of renewable energy projects. In addition, DEGS develops commercial transmission projects. Currently, DEGS has approximately 1,269 net MW of renewable generating capacity in operation as of December 31, 2012.

Rates and Regulation

Duke Energy Ohio Capacity Rider Filing. On August 29, 2012, Duke Energy Ohio filed an application with the PUCO for the establishment of a charge, pursuant to Ohio's state compensation mechanism, for capacity provided consistent with its obligations as an FRR entity. The application included a request for deferral authority and for a new tariff to implement the charge. The deferral being sought is the difference between its costs and market-based prices for capacity. The requested tariff would implement a charge to be collected via a rider through which such deferred balances will subsequently be recovered. 24 parties moved to intervene. Hearings have been set for April 2, 2013. Duke Energy Ohio expects an order in 2013.

Other Matters. As discussed in the USFE&G section above, the PUCO approved Duke Energy Ohio's new ESP in November 2011. In November 2011, as a result of changes resulting from the PUCO's approval of the new ESP, Commercial Power ceased applying regulatory accounting treatment to its Ohio operations. Currently, no portion of Commercial Power applies regulatory accounting.

Commercial Power's Ohio retail load operations' rates were subject to approval by the PUCO through December 2011, and thus these operations, through December 31, 2011, are referred to herein as Commercial Power s regulated operations

For more information on rate matters, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters — Rate Related Information."

Commercial Power is subject to regulation at the federal level, primarily from the FERC Regulations of the FERC govern access to regulated electric customer and other data by nonregulated entities, and services provided between regulated and non-regulated energy affiliates These regulations affect the activities of Commercial Power.

Commercial Power is subject to the jurisdiction of the EPA and state and local environmental agencies. (For a discussion of environmental regulation, see "Environmental Matters" in this section.)

See "Other Issues" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion about potential Global Climate Change legislation and the potential impacts such legislation could have on Duke Energy's operations.

Market Environment and Competition

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Progress Energy Carolinas' service area covers approximately 34,000 square miles, including a substantial portion of the coastal plain of North Carolina extending from the Piedmont to the Atlantic coast between the Pamlico River and the South Carolina border, the lower Piedmont section of North Carolina, an area in western North Carolina in and around the city of Asheville and an area in the northeastern portion of South Carolina. At December 31, 2012, Progress Energy Carolinas was providing electric services to approximately 1.5 million residential, commercial and industrial customers.

The remainder of Progress Energy Carolinas' operations is presented as Other. Although it is not considered a business segment, Other primarily includes certain governance costs allocated by its ultimate parent, Duke Energy.

PROGRESS ENERGY FLORIDA

Progress Energy Florida is a regulated public utility founded in Florida in 1899 and is primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. For information about Progress Energy Florida's generating plants, see Item 2, "Properties." Progress Energy Florida is subject to the regulatory provisions of the FPSC, the NRC and FERC. Progress Energy Florida operates one reportable business segment, Franchised Electric, which generates, transmits, distributes and sells electricity. Substantially all of Franchised Electric operations are regulated and qualify for regulatory accounting treatment. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, "Business Segments."

Progress Energy Florida's service area covers approximately 20,000 square miles in west-central Florida, and includes the densely populated areas around Orlando, as well as the cities of St. Petersburg and Clearwater. Progress Energy Florida is interconnected with 22 municipal and 9 rural electric cooperative systems. At December 31, 2012, Progress Energy Florida was providing electric services to approximately 1.7 million residential, commercial and industrial customers.

The remainder of Progress Energy Florida's operations is presented as Other. Although it is not considered a business segment, Other primarily includes certain governance costs allocated by its ultimate parent, Duke Energy.

DUKE ENERGY OHIO

Duke Energy Ohio is a wholly owned subsidiary of Cinergy, which is a wholly owned subsidiary of Duke Energy. Duke Energy Ohio is a combination electric and gas public utility that provides service in southwestern Ohio and northern Kentucky through its wholly owned subsidiary Duke Energy Kentucky, as well as electric generation in parts of Ohio, Illinois, and Pennsylvania. Duke Energy Ohio's principal lines of business include generation, transmission and distribution of electricity, the sale of and/or transportation of natural gas, and energy marketing. Duke Energy Kentucky's principal lines of business include generation, transmission and distribution of electricity, as well as the sale of and/or transportation of natural gas. References herein to Duke Energy Ohio include Duke Energy Ohio and its subsidiaries. Duke Energy Ohio is subject to the regulatory provisions of the PUCO, the KPSC and FERC.

Duke Energy Ohio Business Segments. At December 31, 2012, Duke Energy Ohio operated two business segments, both of which are considered reportable segments under the applicable accounting rules. Franchised Electric and Gas and Commercial Power. For additional information on each of these business segments, including financial information, see Note 3 to the Consolidated Financial Statements, "Business Segments."

The following is a brief description of the nature of operations of each of Duke Energy Ohio's reportable business segments, as well as Other.

Franchised Electric and Gas

Franchised Electric and Gas consists of Duke Energy Ohio's regulated electric and gas transmission and distribution systems located in Ohio and Kentucky, including its regulated electric generation in Kentucky. Franchised Electric and Gas plans, constructs, operates and maintains Duke Energy Ohio's transmission and distribution systems, which transmit and distribute electric energy to consumers in southwestern Ohio. In addition, Franchised Electric and Gas plans, constructs, operates and maintains Duke Energy Kentucky's generation assets and transmission and distribution systems, which generate, transmit and distribute electric energy to consumers in and northern Kentucky. Franchised Electric and Gas also transports and sells natural gas in southwestern Ohio and northern Kentucky. Substantially all of Franchised Electric and Gas' operations are regulated and, accordingly, these operations qualify for regulatory accounting treatment.

Duke Energy Ohio's Franchised Electric and Gas service area covers 3,000 square miles and supplies electric service to 830,000 residential, commercial and industrial customers and provides regulated transmission and distribution services for natural gas to 500,000 customers. See Item 2. "Properties" for further discussion of Duke Energy Ohio's Franchised Electric and Gas generating facilities.

Commercial Power

Commercial Power owns, operates and manages power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants, as well as other contractual positions. Commercial Power's generation operations consists primarily of coal-fired generation assets located in Ohio and gas-fired nonregulated generation assets which are dispatched into wholesale markets and receive capacity revenues at market rates. These assets are comprised of 6,825 net MW of power generation primarily located in the Midwestern U.S. The asset portfolio has a diversified fuel mix with baseload and mid-merit coal-fired units as well as combined cycle and peaking natural gas-fired units. The coal-fired generation assets were dedicated under the Duke Energy Ohio ESP through December 31, 2011. Duke Energy Ohio's Commercial Power reportable operating segment does not include the operations of DEGS or Duke Energy Retail, which is included in the Commercial Power reportable operating segment at Duke Energy. See Item 2. "Properties", for further discussion of Duke Energy Ohio's Commercial Power generating facilities.

The PUCO approved Duke Energy Ohio's new ESP in November 2011. The ESP includes competitive auctions for electricity supply for a term of January 1, 2012 through May 31, 2015. The ESP also includes a provision for a non-bypassable stability charge of $110 million per year to be collected from 2012-2014 and requires Duke Energy Ohio to transfer its generation assets to a nonregulated affiliate on or before December 31, 2014. As a result of the new ESP, the energy from Duke Energy Ohio's coal-fired generation assets no longer serve retail load customers or receive negotiated pricing under the ESP.

Effective January 1, 2012, Duke Energy Ohio completed its RTO realignment to PJM, and operates as an FRR entity through May 31, 2015. As an FRR entity, Duke Energy Ohio is required to self supply capacity for the Duke Energy Ohio load zone.

See Note 4 to the Consolidated Financial Statements, "Regulatory Matters," for further discussion related to regulatory filings.

In 2012, 2011, and 2010 Duke Energy Ohio earned approximately 36%, 24%, and 13%, respectively, of its consolidated operating revenues from PJM. These revenues relate to the sale of capacity and electricity from all of Duke Energy Ohio's nonregulated generation assets in 2012 and its gas-fired nonregulated generation assets in 2011 and 2010.

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ITEM 2. PROPERTIES

U.S. FRANCHISED ELECTRIC AND GAS

The following table provides information related to USFE&G's electric generation stations as of December 31, 2012. The MW displayed in the table below are based on summer capacity.

Facility	Plant Type	Primary Fuel	Location	Total MW Capacity	Owned MW Capacity	Ownership Interest
Duke Energy Carolinas:						
Oconee	Nuclear	Uranium	SC	2,538	2,538	100 %
Catawba[(a)]	Nuclear	Uranium	SC	2,258	435	19.26
Belews Creek	Fossil Steam	Coal	NC	2,220	2,220	100
McGuire	Nuclear	Uranium	NC	2,200	2,200	100
Marshall	Fossil Steam	Coal	NC	2,078	2,078	100
Cliffside	Fossil Steam	Coal	NC	1,377	1,377	100
Bad Creek	Hydro	Water	SC	1,360	1,360	100
Lincoln	Combustion Turbine	Gas / Oil	NC	1,267	1,267	100
Allen	Fossil Steam	Coal	NC	1,127	1,127	100
Rockingham	Combustion Turbine	Gas / Oil	NC	825	825	100
Jocassee	Hydro	Water	SC	780	780	100
Buck	Combined Cycle	Gas	NC	620	620	100
Dan River	Combined Cycle	Gas	NC	620	620	100
Mill Creek	Combustion Turbine	Gas / Oil	SC	596	596	100
Riverbend[(j)]	Fossil Steam	Coal	NC	454	454	100
Lee	Fossil Steam	Coal	SC	370	370	100
Cowans Ford	Hydro	Water	NC	325	325	100
Buck[(j)]	Fossil Steam	Coal	NC	256	256	100
Keowee	Hydro	Water	SC	152	152	100
Lee	Combustion Turbine	Gas / Oil	SC	82	82	100
Distributed generation	Renewable	Solar	NC	8	8	100
Other small hydro (26 plants)	Hydro	Water	NC / SC	660	660	100
Total Duke Energy Carolinas				22,173	20,350	
Progress Energy Carolinas:						
Roxboro[(b)]	Fossil Steam	Coal	NC	2,417	2,327	96.28 %
Brunswick[(b)]	Nuclear	Uranium	NC	1,870	1,527	81.66
Smith	Combined Cycle	Gas / Oil	NC	1,084	1,084	100
H.F. Lee	Combined Cycle	Gas	NC	920	920	100
Harris[(b)]	Nuclear	Uranium	NC	900	754	83.83
Wayne County	Combustion Turbine	Gas / Oil	NC	863	863	100
Smith	Combustion Turbine	Gas / Oil	NC	820	820	100
Darlington	Combustion Turbine	Gas / Oil	SC	790	790	100
Mayo[(b)]	Fossil Steam	Coal	NC	727	609	83.83
Robinson	Nuclear	Uranium	SC	724	724	100
Sutton[(j)]	Fossil Steam	Coal	NC	575	575	100
Asheville	Fossil Steam	Coal	NC	376	376	100
Asheville	Combustion Turbine	Gas / Oil	NC	324	324	100
Weatherspoon	Combustion Turbine	Gas / Oil	NC	131	131	100
Walters	Hydro	Water	NC	112	112	100
Tillery	Hydro	Water	NC	87	87	100
Sutton	Combustion Turbine	Gas / Oil	NC	61	61	100
Blewett	Combustion Turbine	Oil	NC	52	52	100
Cape Fear	Combustion Turbine	Oil	NC	35	35	100
Blewett	Hydro	Water	NC	22	22	100
Robinson	Combustion Turbine	Gas / Oil	SC	11	11	100
Marshall	Hydro	Water	NC	4	4	100
Total Progress Energy Carolinas				12,905	12,208	
Progress Energy Florida:						
Crystal River	Fossil Steam	Coal	FL	2,295	2,295	100 %
Hines	Combined Cycle	Gas / Oil	FL	1,912	1,912	100
Bartow	Combined Cycle	Gas / Oil	FL	1,133	1,133	100
Anclote	Fossil Steam	Gas / Oil	FL	1,011	1,011	100
Intercession City[(c)]	Combustion Turbine	Gas / Oil	FL	982	982	(c)
Crystal River Unit 3[(d)]	Nuclear	Uranium	FL	860	789	91.78
DeBary	Combustion Turbine	Gas / Oil	FL	638	638	100
Tiger Bay	Combined Cycle	Gas	FL	205	205	100
Bartow	Combustion Turbine	Gas / Oil	FL	177	177	100

Bayboro	Combustion Turbine	Oil	FL	174	174	100
Suwannee River	Combustion Turbine	Gas / Oil	FL	155	155	100
Turner	Combustion Turbine	Oil	FL	137	137	100
Suwannee River	Fossil Steam	Gas / Oil	FL	129	129	100
Higgins	Combustion Turbine	Gas / Oil	FL	105	105	100
Avon Park	Combustion Turbine	Gas / Oil	FL	48	48	100
University of Florida Cogeneration	Combustion Turbine	Gas	FL	46	46	100
Rio Pinar	Combustion Turbine	Oil	FL	12	12	100
Total Progress Energy Florida				10,019	9,948	
Duke Energy Ohio						
East Bend[e]	Fossil Steam	Coal	KY	600	414	69 %
Woodsdale	Combustion Turbine	Gas / Propane	OH	462	462	100
Miami Fort (Unit 6)	Fossil Steam	Coal	OH	163	163	100
Total Duke Energy Ohio				1,225	1,039	
Duke Energy Indiana:						
Gibson[f]	Fossil Steam	Coal	IN	3,132	2,822	90.1 %
Cayuga[g]	Fossil Steam	Coal / Oil	IN	1,005	1,005	100
Wabash River[h]	Fossil Steam	Coal / Oil	IN	676	676	100
Madison	Combustion Turbine	Gas	OH	576	576	100
Vermillion[i]	Combustion Turbine	Gas	IN	568	355	62.5
Wheatland	Combustion Turbine	Gas	IN	460	460	100
Noblesville	Combined Cycle	Gas	IN	285	285	100
Gallagher	Fossil Steam	Coal	IN	280	280	100
Henry County	Combustion Turbine	Gas	IN	129	129	100
Cayuga	Combustion Turbine	Gas / Oil	IN	99	99	100
Connersville	Combustion Turbine	Oil	IN	86	86	100
Miami Wabash	Combustion Turbine	Oil	IN	80	80	100
Markland	Hydro	Water	IN	45	45	100
Total Duke Energy Indiana				7,421	6,898	
Total USFE&G				53,743	50,443	

Totals by plant type:		
Nuclear	11,350	8,967
Fossil Steam	21,268	20,564
Combined Cycle	6,779	6,779
Combustion Turbine	10,791	10,578
Hydro	3,547	3,547
Renewable	8	8
Total USFE&G	53,743	50,443

(a) This generation facility is jointly owned by Duke Energy Carolinas, along with North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation and Piedmont Municipal Power Agency.
(b) This generation facility is jointly owned by Progress Energy Carolinas and the North Carolina Eastern Municipal Power Agency.
(c) Progress Energy Florida owns and operates Intercession City Station Units 1-10 and 12-14. Unit 11 is jointly owned by Progress Energy Florida and Georgia Power Company. Georgia Power Company has the exclusive right to the output of this unit during the months of June through September. Progress Energy Florida has the exclusive right to the output of this unit for the remainder of the year.
(d) Due to the extended outage at the Crystal River Unit 3 nuclear generating unit that began in September 2009 and the related delaminations, no nuclear power was generated in 2012, 2011 or 2010. This generation facility is owned by Progress Energy Florida and various municipal electric companies. In February 2013, Duke Energy announced the retirement of Crystal River Unit 3.
(e) This generation facility is jointly owned by Duke Energy Ohio and a subsidiary of The AES Corporation.
(f) Duke Energy Indiana owns and operates Gibson Station Units 1-4 and owns 50.05% of Unit 5, but is the operator. Unit 5 is jointly owned by Duke Energy Indiana, Wabash Valley Power Association, Inc. and Indiana Municipal Power Agency.
(g) Includes Cayuga Internal Combustion (IC).
(h) Includes Wabash River IC.
(i) This generation facility is jointly owned by Duke Energy Indiana and the Wabash Valley Power Association.
(j) Duke Energy has announced plans to retire these plants in 2013.

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The following table provides information related to USFE&G's electric transmission and distribution properties as of December 31, 2012.

	Duke Energy Carolinas	Progress Energy Carolinas	Progress Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Total USFE&G
Electric transmission lines:						
Miles of 525 KV	600	300	200	-	-	1,100
Miles of 345 KV	-	-	-	1,000	700	1,700
Miles of 230 KV	2,600	3,300	1,700	-	700	8,300
Miles of 100 to 161 KV	6,800	2,600	1,000	700	1,400	12,500
Miles of 13 to 69 KV	3,100	-	2,200	800	2,500	8,600
Total conductor miles of electric transmission lines	13,100	6,200	5,100	2,500	5,300	32,200
Electric distribution lines:						
Miles of overhead lines	66,700	44,600	52,000	14,000	22,600	199,900
Miles of underground line	35,000	22,400	18,700	5,600	8,300	90,000
Total conductor miles of electric distribution lines	101,700	67,000	70,700	19,600	30,900	289,900
Number of electric transmission and distribution substations	1,500	500	500	300	500	3,300
Miles of gas mains	-	-	-	7,200	-	7,200
Miles of gas service lines	-	-	-	6,000	-	6,000

Substantially all of USFE&G's electric plant in service is mortgaged under indentures relating to Duke Energy Carolinas', Progress Energy Carolinas', Progress Energy Florida's, Duke Energy Ohio's and Duke Energy Indiana's various series of First Mortgage Bonds.

COMMERCIAL POWER

The following table provides information related to Commercial Power's electric generation stations as of December 31, 2012. The MW displayed in the table below are based on summer capacity."

Facility	Plant Type	Primary Fuel	Location	Total MW Capacity	Owned MW Capacity	Ownership Interest
Duke Energy Ohio						
Stuart[(a)(b)(c)]	Fossil Steam	Coal	OH	2,308	900	39 %
Zimmer[(a)(c)]	Fossil Steam	Coal	OH	1,300	605	46.5
Hanging Rock	Combined Cycle	Gas	OH	1,226	1,226	100
Beckjord[(a)(c)]	Fossil Steam	Coal	OH	1,024	765	74.7
Miami Fort (Units 7 and 8)[(a)(c)]	Fossil Steam	Coal	OH	1,000	640	64
Conesville[(a)(b)(c)]	Fossil Steam	Coal	OH	780	312	40
Washington	Combined Cycle	Gas	OH	617	617	100
Fayette	Combined Cycle	Gas	PA	614	614	100
Killen[(a)(b)(c)]	Fossil Steam	Coal	OH	600	198	33
Lee	Combustion Turbine	Gas	IL	568	568	100
Beckjord[(c)]	Combustion Turbine	Oil	OH	188	188	100
Dick's Creek[(c)]	Combustion Turbine	Gas	OH	136	136	100
Miami Fort[(c)]	Combustion Turbine	Oil	OH	56	56	100
Total Duke Energy Ohio				10,417	6,825	
Duke Energy Renewables:						
Los Vientos Windpower II	Renewable	Wind	TX	202	202	100 %
Los Vientos Windpower I	Renewable	Wind	TX	200	200	100
Top of the World	Renewable	Wind	WY	200	200	100
Notrees	Renewable	Wind	TX	153	153	100
Campbell Hill	Renewable	Wind	WY	99	99	100
North Allegheny	Renewable	Wind	PA	70	70	100
Laurel Hill Wind Energy	Renewable	Wind	PA	69	69	100
Ocotillo	Renewable	Wind	TX	59	59	100
Kit Carson	Renewable	Wind	CO	51	51	100
Silver Sage	Renewable	Wind	WY	42	42	100
Happy Jack	Renewable	Wind	WY	29	29	100
Shirley	Renewable	Wind	WI	20	20	100
Bagdad	Renewable	Solar	AZ	15	15	100
Washington White Post	Renewable	Solar	NC	12	12	100
TX Solar	Renewable	Solar	TX	14	14	100
Black Mountain	Renewable	Solar	AZ	9	9	100
Other small solar	Renewable	Solar	Various	25	25	100
Total Duke Energy Renewables				1,269	1,269	

Total Commercial Power	**11,686**	**8,094**
Totals by plant type:		
Fossil Steam	7,012	3,420
Combined Cycle	2,457	2,457
Combustion Turbine	948	948
Renewable	1,269	1,269
Total Commercial Power	**11,686**	**8,094**

(a) These generation facilities are jointly owned by Duke Energy Ohio and subsidiaries of American Electric Power Company, Inc. and/or The AES Corporation.

(b) Station is not operated by Duke Energy Ohio.

(c) These generation facilities were dedicated under the ESP through December 31, 2011.

In addition to the above facilities, Commercial Power owns an equity interest in the 585 MW capacity Sweetwater wind projects located in Texas, the 299 MW capacity DS Cornerstone wind projects located in Kansas and the 13 MW capacity INDU Solar Holding JV. Commercial Power's share in these projects in 440 MW.

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INTERNATIONAL ENERGY

The following table provides additional information related to International Energy's electric generation stations as of December 31, 2012. The MW displayed in the table below are based on summer capacity.

Facility	Primary Fuel	Location	Total MW Capacity	Owned MW Capacity	Ownership Interest
Paranapanema[(a)]	Water	Brazil	2,258	2,073	92 %
Egenor	Water / Diesel	Peru	622	622	100
Cerros Colorados	Water / Gas	Argentina	576	524	91
DEI Chile	Water / Diesel / Gas	Chile	380	380	100
DEI El Salvador	Oil / Diesel	El Salvador	328	296	90
DEI Guatemala	Oil / Diesel / Coal	Guatemala	356	356	100
Electroquil	Diesel	Ecuador	192	163	85
Aguaytia	Gas	Peru	170	170	100
Total International Energy			**4,882**	**4,584**	

(a) Includes Canoas I and II, which is jointly owned by Duke Energy and Companhia Brasileira de Aluminio, as well as Duke Energy's wholly owned Palmeiras small hydro plant.

International Energy also owns a 25% equity interest in NMC. In 2012, NMC produced approximately 900,000 metric tons of methanol and in excess of 1 million metric tons of MTBE. Approximately 40% of methanol is normally used in the MTBE production.

OTHER

Duke Energy owns approximately 5.2 million square feet and leases 2.9 million square feet of corporate, regional and district office space spread throughout its service territories and in Houston, Texas.

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DUKE ENERGY OHIO

INTRODUCTION

Management's Discussion and Analysis should be read in conjunction with the accompanying Consolidated Financial Statements and Notes for the years ended December 31, 2012, 2011, and 2010.

BASIS OF PRESENTATION

The results of operations and variance discussion for Duke Energy Ohio is presented in a reduced disclosure format in accordance with General Instruction (I)(2)(a) of Form 10-K.

RESULTS OF OPERATIONS

	Years Ended December 31,		
(in millions)	2012	2011	Variance
Operating revenues	$ 3,152	$ 3,181	$ (29)
Operating expenses	2,810	2,811	(1)
Gains on sales of other assets and other, net	7	5	2
Operating income	349	375	(26)
Other income and expense, net	13	19	(6)
Interest expense	89	104	(15)
Income before income taxes	273	290	(17)
Income tax expense	98	96	2
Net income	$ 175	$ 194	$ (19)

The following table shows the percent changes in Franchised Electric and Gas's GWh sales and average number of customers for Duke Energy Ohio. Except
as otherwise noted, the below percentages represent billed sales only for the periods presented and are not weather normalized.

Increase (decrease) over prior year	2012	2011
Residential sales[(a)]	(3.3) %	(3.2) %
General service sales[(a)]	(2.6) %	(1.2) %
Industrial sales[(a)]	0.6 %	(2.9) %
Wholesale power sales	(35.9) %	15.9 %
Total sales[(b)]	(2.3) %	(2.3) %
Average number of customers	0.5 %	0.2 %

(a) Major components of retail sales.

(b) Consists of all components of sales, including all billed and unbilled retail sales, and wholesale sales to incorporated municipalities and to public and private utilities and power marketers.

The decrease in Duke Energy Ohio's net income for the year ended December 31, 2012 compared to December 31, 2011 was primarily due to the following factors:

Operating revenues. The variance was primarily driven by:

- A $285 million decrease in electric revenues from the coal-fired generation assets driven primarily by the expiration of the 2009-2011 ESP, net of stability charge revenues, partially offset by the coal-fired generation assets participating in the PJM wholesale energy market in 2012,
- A $39 million decrease in electric revenues from the gas-fired generation assets driven primarily by lower power prices, partially offset by increased volumes, and
- An $18 million decrease in PJM capacity revenues related to lower average cleared capacity auction pricing in 2012 compared to 2011 for the gas-fired generation assets, net of an increase associated with the move of the coal-fired assets from MISO to PJM in 2012.

Partially offsetting these decreases were:

- A $279 million increase in regulated fuel and purchased power revenues driven primarily by higher purchased power revenues collected under the new Ohio ESP which became effective January 1, 2012, partially offset by reduced gas sales volumes and lower natural gas costs, and
- A $32 million increase in retail Ohio electric energy efficiency rider revenue resulting primarily from the approval of the final save-a-watt order for the years 2009-2012.

Operating expenses. The variance was primarily driven by:

- A $101 million decrease in operating and maintenance expenses resulting primarily from prior year recognition of MISO exit fees, higher prior year station outages, and regulatory asset amortization expenses,
- An $88 million decrease primarily from the 2011 impairment of excess emission allowances as a result of the EPA's issuance of the Cross-State Air Pollution Rule (CSAPR), and

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- An $85 million decrease in fuel expense from the gas-fired generation assets driven by lower natural gas costs, partially offset by higher volumes.

Partially offsetting these decreases was:

- A $274 million increase in regulated fuel expense driven primarily by higher purchased power expense as a result of the new ESP, partially offset by reduced gas sales volumes and lower natural gas costs.

Interest expense. The variance was primarily due to lower average debt balances in 2012 compared to 2011 and post in-service carrying charges related to new projects.

Income tax expense. The variance in tax expense is primarily due to an increase in the effective tax rate. The effective tax rate for the years ended December 31, 2012 and 2011 was 36.0% and 33.1%, respectively. The increase in the effective tax rate is primarily due to a $10 million reduction of deferred tax liabilities as a result of an election related to the transfer of certain gas-fired generation assets to its wholly owned subsidiary Duke Energy Commercial Asset Management, LLC (DECAM) in the second quarter of 2011.

Matters Impacting Future Duke Energy Ohio Results

Duke Energy Ohio filed electric and gas distribution rate cases in July 2012. These planned rate cases are needed to recover capital investments, costs associated with MGP sites and operating costs. Duke Energy Ohio's earnings could be adversely impacted if these rate cases are denied or delayed by the state regulatory commission.

The current low energy price projections, as well as recently issued and proposed environmental regulations pertaining to coal and coal-fired generating facilities, could impact future cash flows and market valuations of Duke Energy Ohio's coal-fired generation assets which could lead to impairment charges.

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CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The application of accounting policies and estimates is an important process that continues to develop as Duke Energy's operations change and accounting guidance evolves. Duke Energy has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

Management bases its estimates and judgments on historical experience and on other various assumptions that it believes are reasonable at the time of application. The estimates and judgments may change as time passes and more information about Duke Energy's environment becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Duke Energy discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the audit committee, as appropriate. Duke Energy's critical accounting policies and estimates are discussed below.

Regulatory Accounting

Duke Energy's regulated operations (the substantial majority of U.S. Franchised Electric and Gas's operations) meet the criteria for application of regulatory accounting treatment. As a result, Duke Energy records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP in the U.S. for nonregulated entities. Regulatory assets generally represent incurred costs that have been deferred because such costs are probable of future recovery in customer rates. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that have yet to be incurred. Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, historical regulatory treatment for similar costs in Duke Energy's jurisdictions, litigation of rate orders, recent rate orders to other regulated entities, and the status of any pending or potential deregulation legislation. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. This assessment reflects the current political and regulatory climate at the state and federal levels, and is subject to change in the future. If future recovery of costs ceases to be probable, the asset write-offs would be required to be recognized in operating income. Additionally, the regulatory agencies can provide flexibility in the manner and timing of the depreciation of property, plant and equipment, recognition of nuclear decommissioning costs and amortization of regulatory assets or may disallow recovery of all or a portion of certain assets. Total regulatory assets for Duke Energy were $11,741 million and $4,046 million as of December 31, 2012 and 2011, respectively. Total regulatory liabilities were $5,740 million and $3,006 million as of December 31, 2012 and 2011, respectively. The increases in regulatory assets and liabilities are driven primarily by the Progress Energy merger. For further information, see Note 4 to the Consolidated Financial Statements, "Regulatory Matters."

In order to apply regulatory accounting treatment and record regulatory assets and liabilities, certain criteria must be met. In determining whether the criteria are met for its operations, management makes significant judgments, including determining whether revenue rates for services provided to customers are subject to approval by an independent, third-party regulator, whether the regulated rates are designed to recover specific costs of providing the regulated service, and a determination of whether, in view of the demand for the regulated services and the level of competition, it is reasonable to assume that rates set at levels that will recover the operations' costs can be charged to and collected from customers. This final criterion requires consideration of anticipated changes in levels of demand or competition, direct and indirect, during the recovery period for any capitalized costs.

The regulatory accounting rules require recognition of a loss if it becomes probable that part of the cost of a plant under construction or a recently completed plant will be disallowed for ratemaking purposes and a reasonable estimate of the amount of the disallowance can be made. Such assessments can require significant judgment by management regarding matters such as the ultimate cost of a plant under construction, regulatory recovery implications, etc. As discussed in Note 4, "Regulatory Matters," during 2012, 2011 and 2010 Duke Energy Indiana recorded charges of $631 million, $222 million and $44 million, respectively, related to the IGCC plant currently under construction in Edwardsport, Indiana. Management will continue to assess matters as the construction of the plant and the related regulatory proceedings continue, and further charges could be required in 2013 or beyond. Also as discussed in Note 2 to the Consolidated Financial Statements, "Acquisitions and Sales of Other Assets", Duke Energy Carolinas and Progress Energy Carolinas recorded disallowance charges in 2012 in order to gain FERC approval of the merger between Duke Energy and Progress Energy.

As discussed further in Note 1, "Summary of Significant Accounting Policies", and Note 4, "Regulatory Matters," Duke Energy Ohio discontinued the application of regulatory accounting treatment to portions of its generation operations in November 2011 in conjunction with the approval of its new Electric Security Plan by the Public Utilities Commission of Ohio. The effect of this change was immaterial to the financial statements.

Goodwill Impairment Assessments

Duke Energy's goodwill balances are included in the following table.

(in millions)	December 31, 2012	December 31, 2011
U.S. Franchised Electric and Gas	$ 15,950	$ 3,483
Commercial Power	62	69
International Energy	353	297
Total Duke Energy goodwill	$ 16,365	3,849

The Duke Energy allocates goodwill to a reporting unit, which Duke Energy defines as an operating segment or one level below an operating segment. During 2012, Duke Energy recorded $12,467 million of goodwill associated with the merger with Progress Energy. This goodwill represents the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed on the acquisition date, and was preliminarily allocated entirely to the USFE&G segment. The goodwill recognized is subject to change as additional information is obtained about the facts and circumstances that existed as of the acquisition date. See Note 2, "Acquisitions and Sales of Other Assets," for additional information on the merger with Progress Energy.

The remainder of USFE&G's goodwill relates to the acquisition of Cinergy in April 2006. Commercial Power's goodwill resulted from the 2008 acquisition of Catamount Energy Corporation, a leading wind power company located in Rutland, Vermont, and has been allocated to the Renewables reporting unit. International Energy's goodwill resulted from various acquisitions, including $59 million from the 2012 acquisition of Iberoamericana de Energía Ibener S.A. in Chile. See Note 2, "Acquisitions and Sales of Other Assets," for additional information.

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Validation of a contract's fair value is performed by an internal group separate from the Duke Energy Registrants' deal origination areas. While the Duke Energy Registrants use common industry practices to develop their valuation techniques, changes in their pricing methodologies or the underlying assumptions could result in significantly different fair values and income recognition.

Hedging Strategies. The Duke Energy Registrants closely monitor the risks associated with commodity price changes on their future operations and, where appropriate, use various commodity instruments such as electricity, coal and natural gas forward contracts to mitigate the effect of such fluctuations on operations, in addition to optimizing the value of the non-regulated generation portfolio. Duke Energy's primary use of energy commodity derivatives is to hedge the generation portfolio against exposure to the prices of power and fuel.

The majority of instruments used to manage the Duke Energy Registrants' commodity price exposure are either not designated as a hedge or do not qualify for hedge accounting. These instruments are referred to as undesignated contracts. Mark-to-market changes for undesignated contracts entered into by regulated businesses are reflected as regulatory assets or liabilities on the Consolidated Balance Sheets. Undesignated contracts entered into by unregulated businesses are marked-to-market each period, with changes in the fair value of the derivative instruments reflected in earnings.

Certain derivatives used to manage the Duke Energy Registrants' commodity price exposure are accounted for as either cash flow hedges or fair value hedges. To the extent that instruments accounted for as hedges are effective in offsetting the transaction being hedged, there is no impact to the Consolidated Statements of Operations until after delivery or settlement occurs. Accordingly, assumptions and valuation techniques for these contracts have no impact on reported earnings prior to settlement to the extent they are effective. Several factors influence the effectiveness of a hedge contract, including the use of contracts with different commodities or unmatched terms and counterparty credit risk. Hedge effectiveness is monitored regularly and measured at least quarterly.

In addition to the hedge contracts described above and recorded on the Consolidated Balance Sheets, the Duke Energy Registrants enter into other contracts that qualify for the NPNS exception. When a contract meets the criteria to qualify as an NPNS, the Duke Energy registrants apply such exception. Income recognition and realization related to NPNS contracts generally coincide with the physical delivery of power. For contracts qualifying for the NPNS exception, no recognition of the contract's fair value in the Consolidated Financial Statements is required until settlement of the contract as long as the transaction remains probable of occurring.

Generation Portfolio Risks. The Duke Energy Registrants are primarily exposed to market price fluctuations of wholesale power, natural gas, and coal prices in the U.S. Franchised Electric and Gas and Commercial Power segments. The Duke Energy Registrants optimize the value of their wholesale and non-regulated generation portfolios. The portfolios include generation assets (power and capacity), fuel, and emission allowances. Modeled forecasts of future generation output, fuel requirements, and emission allowance requirements are based on forward power, fuel and emission allowance markets. The component pieces of the portfolio are bought and sold based on models and forecasts of generation in order to manage the economic value of the portfolio in accordance with the strategies of the business units. For Duke Energy Carolinas and Duke Energy Indiana, as well as the Kentucky regulated generation owned by Duke Energy Ohio, the generation portfolio not utilized to serve retail operations or committed load is subject to commodity price fluctuations, although the impact on the Consolidated Statements of Operations is partially offset by mechanisms in these regulated jurisdictions that result in the sharing of net profits from these activities with retail customers. Duke Energy Ohio is subject to wholesale commodity price risks for its non-regulated generation portfolio. The non-regulated generation portfolio dispatches all of their electricity into unregulated markets and receives wholesale energy margins and capacity revenues from PJM. Duke Energy Ohio has fully hedged its forecasted coal-fired generation for 2013 Capacity revenues are 100% contracted in PJM through May 2015. International Energy generally hedges its expected generation using long-term bilateral power sales contracts when favorable market conditions exist and it is subject to wholesale commodity price risks for electricity not sold under such contracts. International Energy dispatches electricity not sold under long-term bilateral contracts into unregulated markets and receives wholesale energy margins and capacity revenues from national system operators. Derivative contracts executed to manage generation portfolio risks for delivery periods beyond 2013 are also exposed to changes in fair value due to market price fluctuations of wholesale power, fuel oil and coal. See "Sensitivity Analysis for Generation Portfolio and Derivative Price Risks" below, for more information regarding the effect of changes in commodity prices on the Duke Energy Registrants' net income.

Other Commodity Risks. At December 31, 2012, pre-tax income in 2013 was not expected to be materially impacted for exposures to other commodities' price changes.

Sensitivity Analysis for Generation Portfolio and Derivative Price Risks. The table below summarizes the estimated effect of commodity price changes on the Duke Energy Registrants' pre-tax net income, based on a sensitivity analysis performed as of December 31, 2012 and December 31, 2011 for Duke Energy and Duke Energy Ohio. Forecasted exposure to commodity price risk for Duke Energy Carolinas, Progress Energy Carolinas, Progress Energy Florida and Duke Energy Indiana is not anticipated to have a material adverse effect on their consolidated results of operations in 2013, based on a sensitivity analysis performed as of December 31, 2012. The sensitivity analysis performed as of December 31, 2011 related to forecasted exposure to commodity price risk during 2012 also indicated that commodity price risk would not have a material adverse effect on the consolidated results of operations of Duke Energy Carolinas, Progress Energy Carolinas, Progress Energy Florida and Duke Energy Indiana during 2012 and the impacts of changing commodity prices in their consolidated results of operations for 2012 was insignificant. The following commodity price sensitivity calculations consider existing hedge positions and estimated production levels, as indicated in the table below, but do not consider other potential effects that might result from such changes in commodity prices.

Summary of Sensitivity Analysis for Generation Portfolio and Derivative Price Risks

	Generation Portfolio Risks for 2013[a]		Sensitivities for Derivatives Beyond 2013[b]	
	As of December 31,		As of December 31,	
(in millions)	2012	2011	2012	2011
Potential effect on pre-tax net income assuming a 10% price change in:				
Duke Energy				
Forward wholesale power prices (per MWh)	$ 34	$ 71	$ 103	$ 24
Forward coal prices (per ton)	11	2	-	-
Gas prices (per MMBtu)	21	42	-	-
Duke Energy Ohio				
Forward wholesale power prices (per MWh)	$ 32	$ 69	$ 103	$ 24
Forward coal prices (per ton)	11	2	-	-
Gas prices (per MMBtu)	21	42	-	-

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Progress Energy Florida, an indirect wholly owned subsidiary of Duke Energy, is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in west central Florida. Progress Energy Florida is subject to the regulatory jurisdiction of the Florida Public Service Commission (FPSC), the NRC and the FERC. Substantially all of Progress Energy Florida's operations are regulated and qualify for regulatory accounting treatment. As discussed further in Note 3, Progress Energy Florida's operations include one reportable segment, Franchised Electric.

Duke Energy Ohio, an indirect wholly owned subsidiary of Duke Energy, is a combination electric and gas public utility that provides service in the southwestern portion of Ohio and in northern Kentucky through its wholly owned subsidiary, Duke Energy Kentucky, as well as electric generation in parts of Ohio, Illinois and Pennsylvania. Duke Energy Ohio's principal lines of business include generation, transmission and distribution of electricity, the sale of and/or transportation of natural gas, and energy marketing. Duke Energy Ohio conducts competitive auctions for retail electricity supply in Ohio whereby the energy price is recovered from retail customers. Duke Energy Kentucky's principal lines of business include generation, transmission and distribution of electricity, as well as the sale of and/or transportation of natural gas. References herein to Duke Energy Ohio include Duke Energy Ohio and its subsidiaries, unless otherwise noted. Duke Energy Ohio is subject to the regulatory provisions of the Public Utilities Commission of Ohio (PUCO), the Kentucky Public Service Commission (KPSC) and the FERC. Duke Energy Ohio applies regulatory accounting treatment to substantially all of the operations in its Franchised Electric and Gas operating segment. Through November 2011, Duke Energy Ohio applied regulatory accounting treatment to certain rate riders associated with retail generation of its Commercial Power operating segment. See Note 3 for further information about Duke Energy Ohio's business segments.

Duke Energy Indiana, an indirect wholly owned subsidiary of Duke Energy, is an electric utility that provides service in north central, central, and southern Indiana. Its primary line of business is generation, transmission and distribution of electricity. Duke Energy Indiana is subject to the regulatory provisions of the Indiana Utility Regulatory Commission (IURC) and the FERC. Substantially all of Duke Energy Indiana's operations are regulated and qualify for regulatory accounting treatment. As discussed further in Note 3, Duke Energy Indiana's operations include one reportable business segment, Franchised Electric.

Certain prior year amounts have been reclassified to conform to current year presentation. In addition, prior year financial statements and footnote disclosures for the Progress Energy Registrants have been reclassified to conform to Duke Energy's presentation.

Reverse Stock Split.

On July 2, 2012, just prior to the close of the merger with Progress Energy, Duke Energy executed a one-for-three reverse stock split with respect to the issued and outstanding shares of Duke Energy common stock. All per-share amounts included in this Form 10-K are presented as if the one-for-three reverse stock split had been effective from the beginning of the earliest period presented.

Use of Estimates.

To conform to generally accepted accounting principles (GAAP) in the U.S., management makes estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and Notes. Although these estimates are based on management's best available information at the time, actual results could differ.

Cost-Based Regulation.

The Duke Energy Registrants account for their regulated operations in accordance with applicable regulatory accounting guidance. The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers in a future period or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by an unregulated enterprise. Accordingly, the Duke Energy Registrants record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. Regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process. Management continually assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes, recent rate orders applicable to other regulated entities and the status of any pending or potential deregulation legislation. Additionally, management continually assesses whether any regulatory liabilities have been incurred. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery and that no regulatory liabilities, other than those recorded, have been incurred. These regulatory assets and liabilities are classified in the Consolidated Balance Sheets as Regulatory assets and Other in Current Assets and as Regulatory liabilities and Other in Current Liabilities, respectively. The Duke Energy Registrants periodically evaluate the applicability of regulatory accounting treatment by considering factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, the Duke Energy Registrants may have to reduce their asset balances to reflect a market basis less than cost and write-off the associated regulatory assets and liabilities. If it becomes probable that part of the cost of a plant under construction or a recently completed plant will be disallowed for ratemaking purposes and a reasonable estimate of the amount of the disallowance can be made, that amount is recognized as a loss.

In November 2011, in conjunction with the PUCO's approval of its new Electric Security Plan (ESP), Duke Energy Ohio ceased applying regulatory accounting treatment to generation operations within its Commercial Power segment

For further information, see Note 4.

Energy Purchases, Fuel Costs and Fuel Cost Deferrals.

The Duke Energy Registrants utilize cost-tracking mechanisms, commonly referred to as a fuel adjustment clause, to recover the retail portion of fuel and purchased power. The Duke Energy Registrants defer the related cost through Fuel used in electric generation and purchased power — regulated on the Consolidated Statement of Operations, unless a regulatory requirement exists for deferral through Operating Revenues.

Fuel used in electric generation and purchased power — regulated includes fuel, purchased power and recoverable costs that are deferred through fuel clauses established by the Subsidiary Registrants' regulators. These clauses allow the Subsidiary Registrants to recover fuel costs, fuel-related costs and portions of purchased power costs through surcharges on customer rates. The Subsidiary Registrants record any under-recovery or over-recovery resulting from the differences between estimated and actual costs as a regulatory asset or regulatory

Duke Energy Ohio

Duke Energy Ohio has two reportable operating segments, Franchised Electric and Gas and Commercial Power.

Franchised Electric and Gas transmits and distributes electricity in southwestern Ohio and generates, transmits, distributes and sells electricity in northern Kentucky. Franchised Electric and Gas also transports and sells natural gas in southwestern Ohio and northern Kentucky. It conducts operations primarily through Duke Energy Ohio and its wholly owned subsidiary, Duke Energy Kentucky.

Commercial Power owns, operates and manages power plants and engages in the wholesale marketing and procurement of electric power, fuel and emission allowances related to these plants, as well as other contractual positions. Duke Energy Ohio's Commercial Power reportable operating segment does not include the operations of DEGS or Duke Energy Retail, which are included in the Commercial Power reportable operating segment at Duke Energy.

The remainder of Duke Energy Ohio's operations is presented as Other. While it is not considered an operating segment, Other primarily includes certain governance costs allocated by its parent, Duke Energy. See Note 14 for additional information. All of Duke Energy Ohio's revenues are generated domestically and its long-lived assets are all in the U.S.

Business Segment Data

	Year Ended December 31, 2012					
(in millions)	Franchised Electric and Gas	Commercial Power	Total Reportable Segments	Other	Eliminations	Consolidated Total
Unaffiliated revenues[(a)]	$ 1,745	$ 1,407	$ 3,152	$ —	$ —	$ 3,152
Intersegment revenues	1	51	52	—	(52)	—
Total revenues	$ 1,746	$ 1,458	$ 3,204	$ —	$ (52)	$ 3,152
Interest expense	$ 61	$ 28	$ 89	$ —	$ —	$ 89
Depreciation and amortization	179	159	338	—	—	338
Income tax expense (benefit)	91	25	116	(18)	—	98
Segment income	159	50	209	(34)	—	175
Net income						175
Capital expenditures	427	87	514	—	—	514
Segment assets	6,434	4,175	10,609	117	(166)	10,560

(a) Duke Energy Ohio earned approximately 36% of its consolidated operating revenues from PJM Settlements, Inc. in 2012, all of which is included in the Commercial Power segment. These revenues relate to the sale of capacity and electricity from Commercial Power's non-regulated generation assets.

	Year Ended December 31, 2011					
(in millions)	Franchised Electric and Gas	Commercial Power	Total Reportable Segments	Other	Eliminations	Consolidated Total
Unaffiliated revenues[(a)]	$ 1,474	$ 1,707	$ 3,181	$ —	$ —	$ 3,181
Intersegment revenues	—	4	4	—	(4)	—
Total revenues	$ 1,474	$ 1,711	$ 3,185	$ —	$ (4)	$ 3,181
Interest expense	$ 68	$ 36	$ 104	$ —	$ —	$ 104
Depreciation and amortization	168	167	335	—	—	335
Income tax expense (benefit)	98	6	104	(8)	—	96
Segment income[(b)]	133	78	211	(17)	—	194
Net income						194
Capital expenditures	375	124	499	—	—	499
Segment assets	6,293	4,740	11,033	259	(353)	10,939

(a) Duke Energy Ohio earned approximately 24% of its consolidated operating revenues from PJM Interconnection, LLC (PJM) in 2011, all of which is included in the Commercial Power segment. These revenues relate to the sale of capacity and electricity from Commercial Power's nonregulated generation assets.
(b) Commercial Power recorded an after-tax impairment charge of $51 million, net of tax of $28 million, during the year ended December 31, 2011, to write-down the carrying value of certain emission allowances. See Note 12 for additional information.

	Year Ended December 31, 2010					
(in millions)	Franchised Electric and Gas	Commercial Power	Total Reportable Segments	Other	Eliminations	Consolidated Total
Unaffiliated revenues[(a)]	$ 1,623	$ 1,706	$ 3,329	$ —	$ —	$ 3,329
Intersegment revenues	—	5	5	—	(5)	—
Total revenues	$ 1,623	$ 1,711	$ 3,334	$ —	$ (5)	$ 3,329
Interest expense	$ 68	$ 41	$ 109	$ —	$ —	$ 109
Depreciation and amortization	226	174	400	—	—	400

Income tax expense (benefit)	106	40	146	(14)	—	132
Segment loss[(b)(c)]	(61)	(361)	(422)	(19)	—	(441)
Net loss						(441)
Capital expenditures	353	93	446	—	—	446
Segment assets	6,258	4,821	11,079	192	(247)	11,024

(a) Duke Energy Ohio earned approximately 13% of its consolidated operating revenues from PJM in 2010, all of which is included in the Commercial Power segment. These revenues relate to the sale of capacity and electricity from Commercial Power's nonregulated generation assets.
(b) Franchised Electric and Gas recorded an impairment charge of $216 million related to the Ohio Transmission and Distribution reporting unit. This impairment charge was not applicable to Duke Energy as this reporting unit has a lower carrying value at Duke Energy.
(c) Commercial Power recorded impairment charges of $621 million, which consisted of a $461 million goodwill impairment charge associated with the nonregulated Midwest generation operations and a $102 million charge, net of tax of $58 million, to write-down the value of certain nonregulated Midwest generating assets and emission allowances primarily associated with these generation assets.

addition, the consumer parties will not oppose Progress Energy Florida continuing to pursue a COL for Levy. The 2012 FSPC Settlement Agreement also provides that Progress Energy Florida will treat the allocated wholesale cost of Levy (approximately $68 million) as a retail regulatory asset and include this asset as a component of rate base and amortization expense for regulatory reporting. Progress Energy Florida will have the discretion to accelerate and/or suspend such amortization in full or in part provided that it amortizes all of the regulatory asset by December 31, 2016.

Cost of Removal Reserve. The 2012 and 2010 FPSC Settlement Agreements (Settlement Agreements) provide Progress Energy Florida the discretion to reduce cost of removal amortization expense by up to the balance in the cost of removal reserve until the earlier of (a) its applicable cost of removal reserve reaches zero, or (b) the expiration of the 2012 FPSC Settlement Agreement. Progress Energy Florida may not reduce amortization expense if the reduction would cause it to exceed the appropriate high point of the return on equity range, as established in the Settlement Agreements. Pursuant to the Settlement Agreements, Progress Energy Florida recognized a reduction in amortization expense of $178 million and $250 million for the years ended December 31, 2012 and 2011, respectively. Duke Energy recognized a reduction in amortization expense of $120 million for the year ended December 31, 2012. Progress Energy Florida had eligible cost of removal reserves of $110 million remaining at December 31, 2012, which is impacted by accruals in accordance with its latest depreciation study, removal costs expended and reductions in amortization expense as permitted by the Settlement Agreements.

Anclote Units 1 and 2. On March 29, 2012, Progress Energy Florida announced plans to convert the 1,010 MW Anclote Units 1 and 2 (Anclote) from oil and natural gas fired to 100 percent natural gas fired and requested that the FPSC permit recovery of the estimated $79 million conversion cost through the Environmental Cost Recovery Clause (ECRC). Progress Energy Florida believes this conversion is the most cost-effective alternative for Anclote to achieve and maintain compliance with applicable environmental regulations. On September 13, 2012, the FPSC approved Progress Energy Florida's request to seek cost recovery through the ECRC. Progress Energy Florida anticipates that both converted units will be placed in service by the end of 2013.

Duke Energy Ohio

Capacity Rider Filing. On August 29, 2012, Duke Energy Ohio filed an application with the PUCO for the establishment of a charge, pursuant to Ohio's state compensation mechanism, for capacity provided consistent with its obligations as a Fixed Resource Requirement (FRR) entity. The application included a request for deferral authority and for a new tariff to implement the charge. The deferral being sought is the difference between its costs and market-based prices for capacity. The requested tariff would implement a charge to be collected via a rider through which such deferred balances will subsequently be recovered. 24 parties moved to intervene. Hearings have been set for April 2, 2013. Under the current procedural schedule, Duke Energy Ohio expects an order in 2013.

2012 Electric Rate Case. On July 9, 2012, Duke Energy Ohio filed an application with the PUCO for an increase in electric distribution rates of approximately $87 million. On average, total electric rates would increase approximately 5.1% under the filing. The rate increase is designed to recover the cost of investments in projects to improve reliability for customers and upgrades to the distribution system. Pursuant to a stipulation in another case, Duke Energy Ohio will continue recovering its costs associated with grid modernization in a separate rider.

Duke Energy Ohio expects revised rates, if approved, to go into effect in the first half of 2013.

2012 Natural Gas Rate Case. On July 9, 2012, Duke Energy Ohio filed an application with the PUCO for an increase in natural gas distribution rates of approximately $45 million. On average, total natural gas rates would increase approximately 6.6% under the filing. The rate increase is designed to recover the cost of upgrades to the distribution system, as well as environmental cleanup of manufactured gas plant sites. In addition to the recovery of costs associated with MGP sites, the rate request includes a proposal for an accelerated service line replacement program and a new rider to recover the associated incremental cost. The filing also requests that the PUCO renew the rider recovery of Duke Energy Ohio's accelerated main replacement program and grid modernization program.

On January 4, 2013, the PUCO Staff filed a staff report recommending that Duke Energy Ohio only be allowed to recover costs related to MGP sites which are currently used and useful in the provision of natural gas distribution service. Duke Energy Ohio filed its objection to the staff report on February 4, 2013.

Duke Energy Ohio expects revised rates, if approved, to go into effect in the first half of 2013.

Generation Asset Transfer. On April 2, 2012 and amended on June 22, 2012, Duke Energy Ohio and various affiliated entities filed an Application for Authorization for Disposition of Jurisdictional Facilities with FERC. The application seeks to transfer, from Duke Energy Ohio's rate-regulated Ohio utility company, the legacy coal-fired and combustion gas turbine assets to a nonregulated affiliate, consistent with the ESP stipulation approved by the PUCO on November 22, 2011. The application outlines a potential additional step in the reorganization that would result in a transfer of all of Duke Energy Ohio's Commercial Power business to an indirect wholly owned subsidiary of Duke Energy. The process of determining the optimal corporate structure is an ongoing evaluation of factors, such as tax considerations, that may change between now and the transfer date. In conjunction with the transfer, Duke Energy Ohio's capital structure will be restructured to reflect appropriate debt and equity ratios for its regulated Franchised Electric and Gas operations. The transfer could instead be accomplished within a wholly owned nonregulated subsidiary of Duke Energy Ohio depending on final tax structuring analysis. The FERC approved the application on September 5, 2012. Duke Energy Ohio has agreed to transfer the legacy coal-fired and combustion gas turbine assets on or before December 31, 2014.

Standard Service Offer (SSO). The PUCO approved Duke Energy Ohio's current Electric Security Plan (ESP) on November 22, 2011. The ESP effectively separates the generation of electricity from Duke Energy Ohio's retail load obligation and requires Duke Energy Ohio to transfer its generation assets to a nonregulated affiliate on or before December 31, 2014. The ESP includes competitive auctions for electricity supply whereby the energy price is recovered from retail customers. As a result, Duke Energy Ohio now earns retail margin on the transmission and distribution of electricity only and not on the cost of the underlying energy. New rates for Duke Energy Ohio went into effect for SSO customers on January 1, 2012. The ESP also includes a provision for a non-bypassable stability charge of $110 million per year to be collected from January 1, 2012 through December 31, 2014.

PART II

DUKE ENERGY CORPORATION - DUKE ENERGY CAROLINAS, LLC - PROGRESS ENERGY, INC. – CAROLINA POWER & LIGHT COMPANY d/b/a PROGRESS ENERGY CAROLINAS, INC. – FLORIDA POWER CORPORATION d/b/a PROGRESS ENERY FLORIDA, INC. - DUKE ENERGY OHIO, INC. - DUKE ENERGY INDIANA, INC.

Combined Notes To Consolidated Financial Statements – (Continued)

fair value of the Renewables reporting unit exceeded its carrying value thus no impairment was recorded. The fair value of the Renewables reporting unit is impacted by a multitude of factors, including legislative actions related to tax credit extensions, long-term growth rate assumptions, the market price of power and discount rates. Management continues to monitor these assumptions for any indicators that the fair value of the reporting unit could be below the carrying value, and will assess goodwill for impairment as appropriate.

Midwest Generation Asset Impairment. In the second quarter of 2010, based on circumstances discussed below, management determined that it was more likely than not that the fair value of Commercial Power's nonregulated Midwest generation reporting unit was below its respective carrying value. Accordingly, an interim impairment test was performed for this reporting unit. Determination of reporting unit fair value was based on a combination of the income approach, which estimates the fair value of Duke Energy's reporting units based on discounted future cash flows, and the market approach, which estimates the fair value of Duke Energy's reporting units based on market comparables within the utility and energy industries. Based on completion of step one of the second quarter 2010 impairment analysis, management determined that the fair value of Commercial Power's non-regulated Midwest generation reporting unit was less than its carrying value, which included goodwill of $500 million.

Commercial Power's nonregulated Midwest generation reporting unit includes nearly 4,000 MW of primarily coal-fired generation capacity in Ohio which was dedicated under the ESP through December 31, 2011 Additionally, this reporting unit has approximately 3,600 MW of gas-fired generation capacity in Ohio, Pennsylvania, Illinois and Indiana which provides generation to unregulated energy markets in the Midwest The businesses within Commercial Power's nonregulated Midwest generation reporting unit operate in unregulated markets which allow for customer choice among suppliers As a result, the operations within this reporting unit are subjected to competitive pressures that do not exist in any of Duke Energy's regulated jurisdictions.

Commercial Power's other businesses, including the renewable generation assets, are in a separate reporting unit for goodwill impairment testing purposes. No impairment existed with respect to Commercial Power's renewable generation assets.

The fair value of Commercial Power's nonregulated Midwest generation reporting unit is impacted by a multitude of factors, including current and forecasted customer demand, forecasted power and commodity prices, uncertainty of environmental costs, competition, the cost of capital, valuation of peer companies and regulatory and legislative developments. Management's assumptions and views of these factors continually evolve, and certain views and assumptions used in determining the fair value of the reporting unit in the 2010 interim impairment test changed significantly from those used in the 2009 annual impairment test. These factors had a significant impact on the valuation of Commercial Power's nonregulated Midwest generation reporting unit. More specifically, the following factors significantly impacted management's valuation of the reporting unit:

- Sustained lower forward power prices — In Ohio, Duke Energy's Commercial Power segment provided power to retail customers under the ESP, which utilizes rates approved by the PUCO through 2011. These rates in 2010 were above market prices for generation services, resulting in customers switching to other generation providers. As discussed in Note 4, Duke Energy Ohio will establish a new SSO for retail load customers for generation after the current ESP expires on December 31, 2011. Given forward power prices, which declined from the time of the 2009 impairment, significant uncertainty existed with respect to the generation margin that would be earned under the new SSO.

- Potentially more stringent environmental regulations from the U.S. EPA—In May and July of 2010, the EPA issued proposed rules associated with the regulation of CCRs to address risks from the disposal of CCRs (e.g., ash ponds) and to limit the interstate transport of emissions of NO^x and SO^2. These proposed regulations, along with other pending EPA regulations, could result in significant expenditures for coal fired generation plants, and could result in the early retirement of certain generation assets, which do not currently have control equipment for NO^x and SO2, as soon as 2014.

- Customer switching — ESP customers have increasingly selected alternative generation service providers, as allowed by Ohio legislation, which further erodes margins on sales. In the second quarter of 2010, Duke Energy Ohio's residential class became the target of an intense marketing campaign offering significant discounts to residential customers that switch to alternate power suppliers. Customer switching levels were at approximately 55% at June 30, 2010 compared to approximately 29% in the third quarter of 2009.

As a result of the factors above, a non-cash goodwill impairment charge of $500 million was recorded during the second quarter of 2010. This impairment charge represented the entire remaining goodwill balance for Commercial Power's non-regulated Midwest generation reporting unit. In addition to the goodwill impairment charge, and as a result of factors similar to those described above, Commercial Power recorded $160 million of pre-tax impairment charges related to certain generating assets and emission allowances primarily associated with these generation assets in the Midwest to write-down the value of these assets to their estimated fair value. The generation assets that were subject to this impairment charge were those coal-fired generating assets that do not have certain environmental emissions control equipment, causing these generation assets to be heavily impacted by the EPA's proposed rules on emissions of NOx and SO2. These impairment charges are recorded in Goodwill and Other Impairment Charges on Duke Energy's Consolidated Statement of Operations

Intangible Assets

The following tables show the carrying amount and accumulated amortization of intangible assets.

	December 31, 2012		
(in millions)	Duke Energy	Duke Energy Ohio	Duke Energy Indiana
Emission allowances	$ 80	$ 24	$ 29
Gas, coal and power contracts	295	272	24
Wind development rights	111	—	—
Other	109	10	—
Total gross carrying amounts	595	306	53
Accumulated amortization - gas, coal and power contracts	(180)	(168)	(12)
Accumulated amortization - wind development rights	(9)	—	—
Accumulated amortization - other	(34)	(9)	—
Total accumulated amortization	(223)	(177)	(12)
Total intangible assets, net	$ 372	$ 129	$ 41

Indiana to CRC, an unconsolidated entity formed by a subsidiary of Duke Energy. The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from CRC for a portion of the purchase price. Rental income, interest income and interest expense on these transactions were not material for the years ended December 31, 2012, 2011 and 2010.

In January 2012, Duke Energy Ohio recorded a non-cash equity transfer of $28 million related to the sale of Vermillion to Duke Energy Indiana. Duke Energy Indiana recorded a non-cash after tax equity transfer of $26 million for the purchase of Vermillion from Duke Energy Ohio. See note 2 for further discussion.

DECAM is a non-regulated, direct subsidiary of Duke Energy Ohio. DECAM conducts business activities including the execution of commodity transactions, third party vendor and supply contracts and service contracts for certain of Duke Energy's non-regulated entities. The commodity contracts that DECAM enters either do not qualify as hedges or are accounted for as undesignated contracts, thus the mark-to-market impacts of these contracts are reflected in Duke Energy Ohio's Consolidated Statements of Operations and Comprehensive Income. In addition, equal and offsetting mark-to-market impacts of intercompany contracts with non-regulated entities are reflected in Duke Energy Ohio's Consolidated Statements of Operations and Comprehensive Income representing the pass through of the economics of the original contracts to non-regulated entities in accordance with contractual arrangements between Duke Energy Ohio and non-regulated entities. Because it is not a rated entity, DECAM receives its credit support from Duke Energy or its non-regulated subsidiaries and not the regulated utility operations of Duke Energy Ohio. DECAM meets its funding needs through an intercompany loan agreement from a subsidiary of Duke Energy. DECAM also has the ability to loan money to the subsidiary of Duke Energy. DECAM had an outstanding intercompany loan payable with the subsidiary of Duke Energy of $79 million as of December 31, 2012. This amount is recorded in Notes payable to affiliated companies on Duke Energy Ohio's Consolidated Balance Sheets. DECAM had a $90 million intercompany loan receivable with the subsidiary of Duke Energy as of December 31, 2011. This amount is recorded in Notes receivable from affiliated companies on Duke Energy Ohio's Consolidated Balance Sheets. As discussed in Note 6, in August 2012, Duke Energy issued $1.2 billion of senior unsecured notes. Proceeds from the issuances were used in part to repay outstanding notes of $500 million to DECAM, and such funds were ultimately used to repay at maturity Duke Energy Ohio's $500 million debentures due September 15, 2012. In conjunction with the proposed generation asset transfer discussed in Note 4, Duke Energy Ohio's capital structure is being restructured to reflect appropriate debt and equity ratios for its regulated Franchised Electric and Gas operations.

15. RISK MANAGEMENT, DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Duke Energy Registrants closely monitor the risks associated with commodity price changes and changes in interest rates on their operations and, where appropriate, use various commodity and interest rate instruments to manage these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as hedging instruments, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts). The Duke Energy Registrants' primary use of energy commodity derivatives is to hedge the generation portfolio against exposure to changes in the prices of power and fuel. Interest rate swaps are entered into to manage interest rate risk primarily associated with the Duke Energy Registrants' variable-rate and fixed-rate borrowings.

The accounting guidance for derivatives requires the recognition of all derivative instruments not identified as NPNS as either assets or liabilities at fair value in the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Duke Energy Registrants may elect to designate such derivatives as either cash flow hedges or fair value hedges. The Duke Energy Registrants offset fair value amounts recognized on the Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

The operations of the USFE&G business segment meet the criteria for regulatory accounting treatment. Accordingly, for derivatives designated as cash flow hedges within USFE&G, gains and losses are reflected as a regulatory liability or asset instead of as a component of AOCI. For derivatives designated as fair value hedges or left undesignated within USFE&G, gains and losses associated with the change in fair value of these derivative contracts would be deferred as a regulatory liability or asset, thus having no immediate earnings impact.

Within the Duke Energy Registrants' unregulated businesses, for derivative instruments that qualify for hedge accounting and are designated as cash flow hedges, the effective portion of the gain or loss is reported as a component of AOCI and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Any gains or losses on the derivative that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. For derivative instruments that qualify and are designated as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item are recognized in earnings in the current period. The Duke Energy Registrants include the gain or loss on the derivative in the same line item as the offsetting loss or gain on the hedged item in the Consolidated Statements of Operations. Additionally, the Duke Energy Registrants enter into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as a hedge. The changes in fair value of these undesignated derivative instruments are reflected in current earnings.

Commodity Price Risk

The Duke Energy Registrants are exposed to the impact of market changes in the future prices of electricity (energy, capacity and financial transmission rights), coal, natural gas and emission allowances (SO_2, seasonal NO_X and annual NO_X) as a result of their energy operations such as electricity generation and the transportation and sale of natural gas. With respect to commodity price risks associated with electricity generation, the Duke Energy Registrants are exposed to changes including, but not limited to, the cost of the coal and natural gas used to generate electricity, the prices of electricity in wholesale markets, the cost of capacity and electricity purchased for resale in wholesale markets and the cost of emission allowances primarily at the Duke Energy Registrants' coal fired power plants. Risks associated with commodity price changes on future operations are closely monitored and, where appropriate, various commodity contracts are used to mitigate the effect of such fluctuations on operations. Exposure to commodity price risk is influenced by a number of factors, including, but not limited to, the term of the contract, the liquidity of the market and delivery location.

Commodity Fair Value Hedges. At December 31, 2012, there were no open commodity derivative instruments that were designated as fair value hedges.

D8 6-6168

EXHIBIT 4 OEG
PENGAD 800-631-6989

[redacted]

MASTER POWER PURCHASE AND SALE AGREEMENT
CONFIRMATION LETTER
(06/01/2012-05/31/2013)

This Confirmation Letter (the "Confirmation") shall confirm the Transaction agreed to on October 20, 2011 ("Trade Date") between Duke Energy Ohio, Inc. ("Buyer") and [redacted] ("Seller") regarding the sale/purchase of the Product under the terms and conditions as follows:

RECITALS:

WHEREAS, Buyer is interested in purchasing Cleared Buy Bid Capacity from Seller in the Unconstrained Region also known as the RTO LDA Zone;

WHEREAS, Seller intends to supply the Cleared Buy Bid Capacity to Buyer under the terms and conditions set forth below.

NOW, THEREFORE, in consideration of the promises and mutual covenants set forth herein and the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

GENERAL COMMERCIAL TERMS.

Seller: [redacted]

Buyer: Duke Energy Ohio, Inc.

Product: Subject to Special Conditions set forth below, the Product shall consist of Planning Year 2012-2013 Cleared Buy Bid Capacity from the PJM RPM auction for the Unconstrained Region also known as the RTO LDA Zone, as defined by PJM from time to time ("RTO LDA Zone"), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

Delivery Year: From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2012, through and including HE 2400 EPT, on May 31, 2013 (PJM Planning Year 2012-2013).

Quantity: [redacted] MW

Delivery Point: RTO LDA Zone.

Contract Price: $[redacted] per MW-day

Special Conditions:

Transfer of Product: All Products shall be transferred to Buyer in the manner specified by PJM, including section 4.6.7 of the PJM Manual M-18, or as may otherwise be reasonably requested by Buyer to document the transfer, together with such additional information, documentation and other instruments as may be required by PJM or reasonably requested by

[redacted]

Buyer. The Seller shall transfer this Product between [redacted]

[redacted].

Definitions: Capitalized terms that are used, but not defined herein or in the Master Agreement shall have the meaning ascribed to them in the PJM Agreements. "PJM Agreements" means the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, and any other applicable PJM manuals or documents, or any successor, superseding, or amended versions that may take effect from time to time.

Master Agreement: This Confirmation is being provided pursuant to and in accordance with the ISDA Master Agreement supplemented with a Power Annex (collectively, the "Master Agreement") dated August 1, 2005 between Seller and Buyer, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

Standard of Review: All rates, terms and conditions as specified in this Confirmation hereunder shall remain in effect in accordance with their terms and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act. Absent the agreement of all parties to a proposed change, the standard of review for changes to any section of the Master Agreement or any Confirmation proposed by a party, a non-party, or the FERC acting sua sponte, shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra" doctrine).

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Agreement on their behalf as of the date first above written.

[redacted]

CA[redacted]
CR
LG
DM

Name: [redacted]
Title:
Fax:

Duke Energy Ohio, Inc.

Name: Bryan Smith
Title: Trader
Fax: [redacted]

MASTER POWER PURCHASE AND SALE AGREEMENT
CONFIRMATION LETTER
(06/01/2012-05/31/2013)

This Confirmation Letter (the "Confirmation") shall confirm the Transactions agreed to on December 7, 2011 ("Trade Date") between Duke Energy Ohio, Inc. ("DEO") and [redacted] regarding the exchange of the Products identified in Transaction 1 and transaction 2 below under the terms and conditions as follows:

RECITALS:

WHEREAS, DEO is interested in purchasing unit specific capacity from [redacted] in the Unconstrained Region also known as the RTO LDA in accordance with the terms of Transaction 1 as defined below;

WHEREAS, [redacted] intends to supply the unit specific capacity to DEO utilizing the unit(s) set forth on Schedule 1 attached hereto (collectively, the "Units") subject to the terms and conditions of Transaction 1;

WHEREAS, [redacted] is interested in purchasing cleared buy bid capacity from DEO in accordance with the terms of Transaction 2 as defined below; and

NOW, THEREFORE, in consideration of the premises and mutual covenants set forth herein and the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

<u>Transaction 1</u>

<u>Seller</u>: [redacted]

<u>Buyer</u>: Duke Energy Ohio, Inc.

<u>Product</u>: Subject to Special Conditions set forth below, the Product shall consist of Unit Specific Unforced Capacity from the Units in the Unconstrained Region also known as the RTO LDA , as defined by PJM from time to time ("RTO LDA"), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

<u>Delivery Year:</u> From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2012, through and including HE 2400 EPT, on May 31, 2013.

<u>Quantity:</u> [redacted] MW

<u>Delivery Point:</u> RTO LDA .

<u>Contract Price:</u> $[redacted] per MW-day

<u>Transfer Deadline</u>: Seller shall transfer the Product to Buyer on or before [redacted].

<u>Special Conditions:</u>

Delivery Year Penalties: Seller shall be responsible for all delivery year penalties imposed by PJM during the Delivery Year concerning the Units and their performance including, but not limited to, Peak-Hour Period Availability Charge, Generation Resource Test Failure Charge, any increase in eFORd Penalty Charges and the Peak Season Maintenance Compliance Penalty Charge (collectively the 'Delivery Year Penalties"). If the Buyer is billed by PJM for any Delivery Year Penalties applicable to the Delivery Year associated with the Units, the Buyer shall pay such amount to PJM and shall invoice Seller for all such charges, as determined by Buyer in a commercially reasonable manner, for payment in their next invoice. In the event that the Buyer receives additional monies from PJM for better eFORp performance by the Units ('eFORp Credits") for any Delivery Year, the Buyer shall pay such eFORp Credits, as determined by Buyer in a commercially reasonable manner, to Seller in the next invoice.

Transaction 2

Seller: Duke Energy Ohio, Inc.

Buyer: [redacted]

Product: Subject to Special Conditions set forth below, the Product shall consist of Planning Year 2012-2013 Cleared Buy Bid Capacity from the PJM 1st Incremental RPM auction for the Unconstrained Region also known as the RTO LDA, as defined by PJM from time to time ("RTO LDA"), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

Delivery Year: From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2012, through and including HE 2400 EPT, on May 31, 2013 (PJM Planning Year 2012-2013).

Quantity: [redacted] MW

Delivery Point: RTO LDA

Contract Price: Contract Price: $[redacted] per MW-Day which shall be paid pursuant to the Settlement Procedure set forth below.

Settlement Procedure: The Settlement Procedure shall be as follows: Since PJM invoices the Buyer for the Incremental Auction Charges, upon transfer of the Product to the Buyer in PJM's eRPM System, the Seller will be released from the Incremental Auction Charge associated with the respective Quantity of Product sold hereunder, and the Buyer shall pay directly to PJM the Incremental Auction Charge of $ $[redacted] per MW-Day for the Quantity of Product purchased under this Confirmation. For billing purposes, Seller shall issue an invoice each month to Buyer that reflects the following: (i) Contract Price of $[redacted] per MW-Day of Product (owed by Buyer to Seller) - incremental auction charge of $ $[redacted] per MW-Day for the Quantity of Product (Owed by Seller to PJM but paid by Buyer) = $[redacted] per MW-Day for the Quantity of Product (credit owed by Seller to Buyer is $[redacted] per MW-Day). Provided that Buyer pays PJM directly for the Product as set forth in this Settlement Procedure, Seller shall issue a credit to Buyer each month pursuant to this Confirmation equal to $[redacted] per MW-Day for the Quantity of Product sold to Buyer.

GENERAL COMMERCIAL TERMS (Transaction 1 and 2).

Definitions: For the purposes of this Confirmation, "PJM" shall mean PJM Interconnection LLC or any successor thereto. Capitalized terms that are used, but not defined herein or in the Master Agreement shall have the meaning ascribed to them in the PJM Agreements. "PJM Agreements" means the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, and any other applicable PJM manuals or documents, or any successor, superseding, or amended versions that may take effect from time to time.

Transfer of Product: All Product shall be transferred to Buyer in the manner specified by PJM or as may otherwise be reasonably requested by Buyer to document that transfer, together with such additional information, documentation and other instruments as may be required by PJM or reasonably requested by Buyer.

Master Agreement: This Confirmation is being provided pursuant to and in accordance with the ISDA Master Agreement supplemented with a Power Annex (collectively, the "Master Agreement") dated March 1, 2011 between Seller and Buyer, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

Standard of Review: All rates, terms and conditions as specified in this Confirmation hereunder shall remain in effect in accordance with their terms and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act. Absent the agreement of all parties to a proposed change, the standard of review for changes to any section of the Master Agreement or any Confirmation proposed by a party, a non-party, or the FERC acting sua sponte, shall be the "public interest" application of the "just and reasonable" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) and clarified in Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish 554 U.S. 527 (2008) (the "Mobile-Sierra" doctrine).

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Confirmation on their behalf as of the date first above written.

[redacted]	**Duke Energy Ohio, Inc.**
	By: Bryan L. Garnett
	Name: Bryan L. Garnett
Title: President	Title: Power Trader

Schedule 1

The Units shall consist of the following:

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]

2864784

#2241725

MASTER POWER PURCHASE AND SALE AGREEMENT
CONFIRMATION LETTER
(06/01/2012-05/31/2013)

This Confirmation Letter (the "Confirmation") shall confirm the Transaction agreed to on October 17, 2011 ("Trade Date") between Duke Energy Ohio, Inc. ("Buyer") and [redacted] ("Seller") regarding the sale/purchase of the Product under the terms and conditions as follows:

RECITALS:

WHEREAS, Buyer is interested in purchasing unit specific capacity from Seller in the Unconstrained Region also known as the RTO LDA Zone;-

WHEREAS, Seller intends to supply the unit specific capacity to Buyer utilizing the following units (collectively, the "Units"): [redacted] units subject to the terms and conditions set forth below.

NOW, THEREFORE, in consideration of the promises and mutual covenants set forth herein and the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

GENERAL COMMERCIAL TERMS.

Seller: [redacted]

Buyer: Duke Energy Ohio, Inc.

Product: Subject to Special Conditions set forth below, the Product shall consist of Unit Specific Unforced Capacity from the Units in the Unconstrained Region also known as the RTO LDA Zone, as defined by PJM from time to time ("RTO LDA Zone"), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

Delivery Year: From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2012, through and including HE 2400 EPT, on May 31, 2013.

Quantity: [redacted] MW

Delivery Point: RTO LDA Zone.

Contract Price: $[redacted] per MW-day

Transfer Deadline: Seller shall transfer the Product to Buyer on or before [redacted].

Special Conditions:

Product: Seller shall bear all risks associated with changes in the forced outage of the Generation Capacity Resource designated by Seller as set forth below.

Changes in EFORd Ratings: Final EFORd ratings for the Units will be finalized by PJM in January prior to the start of the Delivery Year. If the EFORd rating increases from what was utilized by Buyer to calculate the quantity of Product purchased under this Confirmation as of the Trade Date, then the Seller will provide to the Buyer a replacement amount of unit specific capacity resources in MWs equal to the amount by which the EFORd rating increased from what was utilized on the Trade Date, but limited to increments of 0.1 MWs as the minimal amount. The replacement product shall be provided by Seller through a *Bilateral Unit-Specific Transaction (as defined in the PJM Agreements)* before the third incremental auction. If the EFORd decreases from what was utilized by Buyer to calculate the quantity of Product purchased under this Confirmation as of the Trade Date, then the Buyer will provide to the Seller a replacement amount of unit specific capacity resources in MWs equal to the amount by which the EFORd rating decreased from what was utilized on the Trade Date, but limited to increments of 0.1 MWs as the minimal amount. The replacement product will be provided by Buyer through a Bilateral Unit-Specific Transaction before the third incremental auction.

The preceding paragraph shall not apply in the event Seller delivers the Product between [redacted].

Delivery Year Penalties: Seller shall be responsible for all delivery year penalties imposed by PJM during the Delivery Year concerning the Units and their performance including, but not limited to, Peak-Hour Period Availability Charge, Generation Resource Test Failure Charge, any increase in eFORd Penalty Charges and the Peak Season Maintenance Compliance Penalty Charge (collectively the 'Delivery Year Penalties"). If the Buyer is billed by PJM for any Delivery Year Penalties applicable to the Delivery Year associated with the Units, the Buyer shall pay such amount to PJM and shall invoice Seller for all such charges, as determined by Buyer in a commercially reasonable manner, for payment in their next invoice. In the event that the Buyer receives additional monies from PJM for better eFORp performance by the Units ('eFORp Credits") for any Delivery Year, the Buyer shall pay such eFORp Credits, as determined by Buyer in a commercially reasonable manner, to Seller in the next invoice.

Transfer of Product: All Products shall be transferred to Buyer in the manner specified by PJM or as may otherwise be reasonably requested by Buyer to document that transfer, together with such additional information, documentation and other instruments as may be required by PJM or reasonably requested by Buyer.

Definitions: Capitalized terms that are used, but not defined herein or in the Master Agreement shall have the meaning ascribed to them in the PJM Agreements. "PJM Agreements" means the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, and any other applicable PJM manuals or documents, or any successor, superseding, or amended versions that may take effect from time to time.

Master Agreement: This Confirmation is being provided pursuant to and in accordance with the ISDA Master Agreement supplemented with a Power Annex (collectively, the "Master Agreement") dated August 1, 2005 between Seller and Buyer, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

Standard of Review: All rates, terms and conditions as specified in this Confirmation hereunder shall remain in effect in accordance with their terms and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act. Absent the agreement of all parties to a proposed change, the standard of review for changes to any section of the Master Agreement or any Confirmation proposed by a party, a non-party, or the FERC acting sua sponte, shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra" doctrine).

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Agreement on their behalf as of the date first above written.

[redacted]	Duke Energy Ohio, Inc.
Name: [redacted]	Name: [illegible]
Title: Manager, Power Trading	Title: Trader
Fax: [redacted]	Fax: 513-419-5152

[redacted]

DEO#[redacted]

[redacted]

[redacted]

May 22, 2012

Duke Energy Ohio, Inc.

To Whom It May Concern:

This letter shall serve as an addendum (Addendum") to the Master Power Purchase and Sale Agreement Confirmation Letter entered into between Duke Energy Ohio, Inc. and [redacted] on August 26, 2011, a copy of which is attached hereto as Exhibit A ("Agreement") and upon execution hereof shall become a part of the Agreement.

Addition to Special Conditions:

Must Offer Requirement: [redacted] shall retain the PJM Capacity "Must Offer Requirement" associated with the Elgin Energy Center for the contract Delivery Year.

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Addendum on their behalf effective as of the date first above written.

[redacted]	Duke Energy Ohio, Inc.
Name: [redacted]	Name: Brian Smith
Title: Manager, Power Trading	Title: Trader
Fax: [redacted]	Fax: 513-287-2693

09/16/2011 15:22 [redacted] [redacted] PAGE 01/03

09/13/2011 13:54 [redacted] [redacted] PAGE 01/03

#853044 Exhibit A #2212802

MASTER POWER PURCHASE AND SALE AGREEMENT CONFIRMATION LETTER (06/01/2012-05/31/2013)

This Confirmation Letter (the "Confirmation") shall confirm the Transaction agreed to on August 26, 2011 ("Trade Date") between Duke Energy Ohio ("Buyer") and [redacted] regarding the sale/purchase of the Product under the terms and conditions as follows:

RECITALS:

WHEREAS, Buyer is interested in purchasing unit specific capacity from Seller in the Unconstrained Region also known as the RTO LDA Zone;

WHEREAS, Seller intends to supply the unit specific capacity to Buyer utilizing the [redacted] units (collectively, the "Units"):; subject to the terms and conditions set forth below; and

NOW, THEREFORE, in consideration of the premises and mutual covenants set forth herein and the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

GENERAL COMMERCIAL TERMS.

Seller: [redacted]

Buyer: Duke Energy Ohio

Product: Subject to Special Conditions set forth below, the Product shall consist of Unit Specific Unforced Capacity from the Units in the Unconstrained Region also known as the RTO LDA Zone, as defined by PJM from time to time ("RTO LDA Zone"), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

Delivery Year: From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2012, through and including HE 2400 EPT, on May 31, 2013.

Quantity: [redacted] MW

Delivery Point: RTO LDA Zone.

Contract Price: $[redacted] per MW-day

Special Conditions:

Product: Seller shall bear all risk associated with changes in the forced outage of the Generation Capacity Resource designated by Seller as set forth below.

Changes in EFORd Ratings: Final EFORd ratings for the Units will be finalized by PJM on or before [redacted]. If the EFORd rating increases from what was

Changes in EFORd Ratings: Final EFORd ratings for the Units will be finalized by PJM in January prior to the start of the Delivery Year. If the EFORd rating increases from what was utilized by Buyer to calculate the quantity of Product purchased under this Confirmation as of the Trade Date, then the Seller will provide to the Buyer a replacement amount of unit specific capacity resources in MWs equal to the amount by which the EFORd rating increased from what was utilized on the Trade Date, but limited to increments of 0.1 MWs as the minimal amount. The replacement product shall be provided by Seller through a Bilateral Unit-Specific Transaction (as defined in the PJM Agreements) before the third incremental auction. If the EFORd decreases from what was utilized by Buyer to calculate the quantity of Product purchased under this Confirmation as of the Trade Date, then the Buyer will provide to the Seller a replacement amount of unit specific capacity resources in MWs equal to the amount by which the EFORd rating decreased from what was utilized on the Trade Date, but limited to increments of 0.1 MWs as the minimal amount. The replacement product will be provided by Buyer through a Bilateral Unit-Specific Transaction before the third incremental auction.

The preceding paragraph shall not apply in the event Seller delivers the Product between [redacted].

Delivery Year Penalties: Seller shall be responsible for all delivery year penalties imposed by PJM during the Delivery Year concerning the Units and their performance including, but not limited to, Peak-Hour Period Availability Charge, Generation Resource Test Failure Charge, any increase in eFORd Penalty Charges and the Peak Season Maintenance Compliance Penalty Charge (collectively the "Delivery Year Penalties"). If the Buyer is billed by PJM for any Delivery Year Penalties applicable to the Delivery Year associated with the Units, the Buyer shall pay such amount to PJM and shall invoice Seller for all such charges, as determined by Buyer in a commercially reasonable manner, for payment in their next invoice. In the event that the Buyer receives additional monies from PJM for better eFORp performance by the Units ("eFORp Credits") for any Delivery Year, the Buyer shall pay such eFORp Credits, as determined by Buyer in a commercially reasonable manner, to Seller in the next invoice.

Transfer of Product: All Products shall be transferred to Buyer in the manner specified by PJM or as may otherwise be reasonably requested by Buyer to document that transfer, together with such additional information, documentation and other instruments as may be required by PJM or reasonably requested by Buyer.

Definitions: Capitalized terms that are used, but not defined herein or in the Master Agreement shall have the meaning ascribed to them in the PJM Agreements. "PJM Agreements" means the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, and any other applicable PJM manuals or documents, or any successor, superseding, or amended versions that may take effect from time to time.

Master Agreement: This Confirmation is being provided pursuant to and in accordance with the ISDA Master Agreement supplemented with a Power Annex (collectively, the "Master Agreement") dated August 1, 2005 between Seller and Buyer, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

Standard of Review: All rates, terms and conditions as specified in this Confirmation hereunder shall remain in effect in accordance with their terms and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act. Absent the agreement of all parties to a proposed change, the standard of review for changes to any section of the Master Agreement or any Confirmation proposed by a party, a non-party, or the FERC acting sua sponte, shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra" doctrine).

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Agreement on their behalf as of the date first above written.

[redacted]	Duke Energy Ohio, Inc.
Name: [redacted]	Name: [signature]
Title: Manager, Power Trading	Title: Trader
Fax: [redacted]	Fax: 513-419-5152

CA
CR
LGI
DM [redacted]

MASTER POWER PURCHASE AND SALE AGREEMENT CONFIRMATION LETTER (06/01/2012-05/31/2013)

This Confirmation Letter (the "Confirmation") shall confirm the Transactions agreed to on December 7, 2011 ("Trade Date") between Duke Energy Ohio, Inc. ("DEO") and [redacted] regarding the exchange of the Products identified in Transaction 1 and transaction 2 below under the terms and conditions as follows:

RECITALS:

WHEREAS, DEO is interested in purchasing unit specific capacity from [redacted] in the Unconstrained Region also known as the RTO LDA in accordance with the terms of Transaction 1 as defined below;

WHEREAS, [redacted] intends to supply the unit specific capacity to DEO utilizing the unit(s) set forth on Schedule 1 attached hereto (collectively, the "Units") subject to the terms and conditions of Transaction 1;

WHEREAS, [redacted] is interested in purchasing cleared buy bid capacity from DEO in accordance with the terms of Transaction 2 as defined below; and

NOW, THEREFORE, in consideration of the premises and mutual covenants set forth herein and the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

Transaction 1

Seller: [redacted]

Buyer: Duke Energy Ohio, Inc.

Product: Subject to Special Conditions set forth below, the Product shall consist of Unit Specific Unforced Capacity from the Units in the Unconstrained Region also known as the RTO LDA, as defined by PJM from time to time ("RTO LDA"), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

Delivery Year: From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2012, through and including HE 2400 EPT, on May 31, 2013.

Quantity: [redacted] MW

Delivery Point: RTO LDA.

Contract Price: $[redacted] per MW-day

Transfer Deadline: Seller shall transfer the Product to Buyer on or before [redacted].

Special Conditions:

Delivery Year Penalties: Seller shall be responsible for all delivery year penalties imposed by PJM during the Delivery Year concerning the Units and their performance including, but not limited to, Peak-Hour Period Availability Charge, Generation Resource Test Failure Charge, any increase in eFORd Penalty Charges and the Peak Season Maintenance Compliance Penalty Charge (collectively the 'Delivery Year Penalties"). If the Buyer is billed by PJM for any Delivery Year Penalties applicable to the Delivery Year associated with the Units, the Buyer shall pay such amount to PJM and shall invoice Seller for all such charges, as determined by Buyer in a commercially reasonable manner, for payment in their next invoice. In the event that the Buyer receives additional monies from PJM for better eFORp performance by the Units ('eFORp Credits") for any Delivery Year, the Buyer shall pay such eFORp Credits, as determined by Buyer in a commercially reasonable manner, to Seller in the next invoice.

Transaction 2

Seller: Duke Energy Ohio

Buyer: [redacted]

Product: Subject to Special Conditions set forth below, the Product shall consist of Planning Year [redacted] Cleared Buy Bid Capacity from the PJM 2nd Incremental RPM auction for the Unconstrained Region also known as the RTO LDA , as defined by PJM from time to time ("RTO LDA "), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

Delivery Year: From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2012, through and including HE 2400 EPT, on May 31, 2013 (PJM Planning Year 2012-2013).

Quantity: [redacted] MW

Delivery Point: RTO LDA

Contract Price: Contract Price: $[redacted] per MW-Day which shall be paid pursuant to the Settlement Procedure set forth below.

Settlement Procedure: The Settlement Procedure shall be as follows: Since PJM invoices the Buyer for the Incremental Auction Charges, upon transfer of the Product to the Buyer in PJM's eRPM System, the Seller will be released from the Incremental Auction Charge associated with the respective Quantity of Product sold hereunder, and the Buyer shall pay directly to PJM the Incremental Auction Charge of $ $[redacted].

GENERAL COMMERCIAL TERMS (Transaction 1 and 2).

Definitions: For the purposes of this Confirmation, "PJM" shall mean PJM Interconnection LLC or any successor thereto. Capitalized terms that are used, but not defined herein or in the Master Agreement shall have the meaning ascribed to them in the PJM Agreements. "PJM Agreements" means the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, and any other applicable PJM manuals or documents, or any successor, superseding, or amended versions that may take effect from time to time.

Transfer of Product: All Product shall be transferred to Buyer in the manner specified by PJM or as may otherwise be reasonably requested by Buyer to document that transfer, together with such additional information, documentation and other instruments as may be required by PJM or reasonably requested by Buyer.

Master Agreement: This Confirmation is being provided pursuant to and in accordance with the ISDA Master Agreement supplemented with a Power Annex (collectively, the "Master Agreement") dated March 1, 2011 between Seller and Buyer, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

Standard of Review: All rates, terms and conditions as specified in this Confirmation hereunder shall remain in effect in accordance with their terms and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act. Absent the agreement of all parties to a proposed change, the standard of review for changes to any section of the Master Agreement or any Confirmation proposed by a party, a non-party, or the FERC acting sua sponte, shall be the "public interest" application of the "just and reasonable" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) and clarified in Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish 554 U.S. 527 (2008) (the "Mobile-Sierra" doctrine).

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Confirmation on their behalf as of the date first above written.

[redacted]	**Duke Energy Ohio, Inc.**
By: [redacted]	By: Bryan L. Garnett
Name: [redacted]	Name: Bryan L. Garnett
Title: President	Title: Power Trader

Schedule 1

The Units shall consist of the following:

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]

MASTER POWER PURCHASE AND SALE AGREEMENT
CONFIRMATION LETTER
(06/01/2013-05/31/2014)

This Confirmation Letter (the "Confirmation") shall confirm the Transactions agreed to on December 7, 2011 ("Trade Date") between Duke Energy Ohio, Inc. ("DEO") and [redacted] regarding the exchange of the Products identified in Transaction 1 and transaction 2 below under the terms and conditions as follows:

RECITALS:

WHEREAS, DEO is interested in purchasing unit specific capacity from [redacted] in the Unconstrained Region also known as the RTO LDA in accordance with the terms of Transaction 1 as defined below;

WHEREAS, [redacted] intends to supply the unit specific capacity to DEO utilizing the unit(s) set forth on Schedule 1 attached hereto (collectively, the "Units") subject to the terms and conditions of Transaction 1;

WHEREAS, [redacted] is interested in purchasing cleared buy bid capacity from DEO in accordance with the terms of Transaction 2 as defined below; and

NOW, THEREFORE, in consideration of the premises and mutual covenants set forth herein and the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

Transaction 1

Seller: [redacted]

Buyer: Duke Energy Ohio, Inc.

Product: Subject to Special Conditions set forth below, the Product shall consist of Unit Specific Unforced Capacity from the Units in the Unconstrained Region also known as the RTO LDA, as defined by PJM from time to time ("RTO LDA"), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

Delivery Year: From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2013, through and including HE 2400 EPT, on May 31, 2014.

Quantity: [redacted] MW

Delivery Point: RTO LDA.

Contract Price: $[redacted] per MW-day

Transfer Deadline: Seller shall transfer the Product to Buyer on or before [redacted].

Special Conditions:

Delivery Year Penalties: Seller shall be responsible for all delivery year penalties imposed by PJM during the Delivery Year concerning the Units and their performance including, but not limited to, Peak-Hour Period Availability Charge, Generation Resource Test Failure Charge, any increase in eFORd Penalty Charges and the Peak Season Maintenance Compliance Penalty Charge (collectively the 'Delivery Year Penalties"). If the Buyer is billed by PJM for any Delivery Year Penalties applicable to the Delivery Year associated with the Units, the Buyer shall pay such amount to PJM and shall invoice Seller for all such charges, as determined by Buyer in a commercially reasonable manner, for payment in their next invoice. In the event that the Buyer receives additional monies from PJM for better eFORp performance by the Units ('eFORp Credits") for any Delivery Year, the Buyer shall pay such eFORp Credits, as determined by Buyer in a commercially reasonable manner, to Seller in the next invoice.

Transaction 2

Seller: Duke Energy Ohio, Inc.

Buyer: [redacted]

Product: Subject to Special Conditions set forth below, the Product shall consist of Planning Year 2013-2014 Cleared Buy Bid Capacity from the PJM 1st Incremental RPM auction for the Unconstrained Region also known as the RTO LDA, as defined by PJM from time to time ("RTO LDA"), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

Delivery Year: From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2013, through and including HE 2400 EPT, on May 31, 2014 (PJM Planning Year 2013-2014).

Quantity: [redacted] MW

Delivery Point: RTO LDA

Contract Price: Contract Price: $[redacted] per MW-Day which shall be paid pursuant to the Settlement Procedure set forth below.

Settlement Procedure: The Settlement Procedure shall be as follows: Since PJM invoices the Buyer for the Incremental Auction Charges, upon transfer of the Product to the Buyer in PJM's eRPM System, the Seller will be released from the Incremental Auction Charge associated with the respective Quantity of Product sold hereunder, and the Buyer shall pay directly to PJM the Incremental Auction Charge of $ $[redacted].

GENERAL COMMERCIAL TERMS (Transaction 1 and 2).

Definitions: For the purposes of this Confirmation, "PJM" shall mean PJM Interconnection LLC or any successor thereto. Capitalized terms that are used, but not defined herein or in the Master Agreement shall have the meaning ascribed to them in the PJM Agreements. "PJM

Agreements" means the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, and any other applicable PJM manuals or documents, or any successor, superseding, or amended versions that may take effect from time to time.

Transfer of Product: All Product shall be transferred to Buyer in the manner specified by PJM or as may otherwise be reasonably requested by Buyer to document that transfer, together with such additional information, documentation and other instruments as may be required by PJM or reasonably requested by Buyer.

Master Agreement: This Confirmation is being provided pursuant to and in accordance with the ISDA Master Agreement supplemented with a Power Annex (collectively, the "Master Agreement") dated March 1, 2011 between Seller and Buyer, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

Standard of Review: All rates, terms and conditions as specified in this Confirmation hereunder shall remain in effect in accordance with their terms and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act. Absent the agreement of all parties to a proposed change, the standard of review for changes to any section of the Master Agreement or any Confirmation proposed by a party, a non-party, or the FERC acting sua sponte, shall be the "public interest" application of the "just and reasonable" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) and clarified in Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish 554 U.S. 527 (2008) (the "Mobile-Sierra" doctrine).

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Confirmation on their behalf as of the date first above written.

[redacted]	**Duke Energy Ohio, Inc.**
By: [redacted]	By: Bryan L. Garnett
Name: [redacted]	Name: Bryan L. Garnett
Title: President	Title: Power Trader

Schedule 1

The Units shall consist of the following:

1. [redacted]
2. [redacted]
3. [redacted]
4. [redacted]

2820579

MASTER POWER PURCHASE AND SALE AGREEMENT CONFIRMATION LETTER (06/01/2014-05/31/2015)

This Confirmation Letter (the "Confirmation") shall confirm the Transaction agreed to on June 17, 2011 ("Trade Date") between Duke Energy Ohio, Inc. ("Buyer") and [redacted] ("Seller") regarding the sale/purchase of the Product under the terms and conditions as follows:

RECITALS:

WHEREAS, Buyer is interested in purchasing unit specific capacity from Seller in the Unconstrained Region also known as the RTO LDA Zone;

WHEREAS, Seller intends to supply the unit specific capacity to Buyer utilizing the units set forth on Schedule I attached hereto (collectively, the "Units") subject to the terms and conditions set forth below; and

NOW, THEREFORE, in consideration of the premises and mutual covenants set forth herein and the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

GENERAL COMMERCIAL TERMS.

Seller: [redacted]

Buyer: Duke Energy Ohio, Inc.

Product: Subject to Special Conditions set forth below, the Product shall consist of Unit Specific Unforced Capacity from the Units in the Unconstrained Region also known as the RTO LDA Zone, as defined by PJM from time to time ("RTO LDA Zone"), pursuant to the PJM Reliability Assurance Agreement, or any successor thereto ("RAA").

Delivery Year: From and including Hour Ending ("HE") 0100 Eastern Prevailing Time ("EPT") on June 1, 2014, through and including HE 2400 EPT, on May 31, 2015.

Quantity: [redacted] MW

Delivery Point: RTO LDA Zone.

Contract Price: $[redacted]/mw-day

Special Conditions:

Product: Seller shall bear all risk associated with changes in the forced outage of the Generation Capacity Resource designated by Seller as set forth below.

Changes in EFORd Ratings: Final EFORd ratings for the Units will be finalized by PJM in January prior to the start of the Delivery Year. If the EFORd rating increases from what was utilized by Buyer to calculate the quantity of Product purchased under this Confirmation as of the Trade Date, then the Seller will provide to the Buyer a replacement amount of unit specific capacity resources in MWs equal to the amount by which the EFORd rating increased from what was utilized on the Trade Date but, limited to increments of 0.1 MWs as the minimal amount. The replacement product shall be provided by Seller through a Bilateral Unit-Specific Transaction (as defined in the PJM Agreements) before the third incremental auction. If the EFORd decreases from what was utilized by Buyer to calculate the quantity of Product purchased under this Confirmation as of the Trade Date, then the Buyer will provide to the Seller a replacement amount of unit specific capacity resources in MWs equal to the amount by which the EFORd rating decreased from what was utilized on the Trade Date but, limited to increments of 0.1 MWs as the minimal amount. The replacement product will be provided by Buyer through a Bilateral Unit-Specific Transaction before the third incremental auction.

Delivery Year Penalties: Seller shall be responsible for all delivery year penalties imposed by PJM during the Delivery Year concerning the Units and their performance including, but not limited to, Peak-Hour Period Availability Charge, Generation Resource Test Failure Charge, any increase in eFORd Penalty Charges and the Peak Season Maintenance Compliance Penalty Charge (collectively the 'Delivery Year Penalties"). If the Buyer is billed by PJM for any Delivery Year Penalties applicable to the Delivery Year associated with the Units, the Buyer shall pay such amount to PJM and shall invoice Seller for all such charges for payment in their next invoice. In the event that the Buyer receives additional monies from PJM for better eFORp performance by the Units ('eFORp Credits") for any Delivery Year, the Buyer shall pay such eFORp Credits to Seller in the next invoice.

Transfer of Product: All Product shall be transferred to Buyer in the manner specified by PJM or as may otherwise be reasonably requested by Buyer to document that transfer, together with such additional information, documentation and other instruments as may be required by PJM or reasonably requested by Buyer.

Definitions: Capitalized terms that are used, but not defined herein or in the Master Agreement shall have the meaning ascribed to them in the PJM Agreements. "PJM Agreements" means the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, and any other applicable PJM manuals or documents, or any successor, superseding, or amended versions that may take effect from time to time.

Master Agreement: This Confirmation is being provided pursuant to and in accordance with the ISDA Master Agreement supplemented with a Power Annex (collectively, the "Master Agreement") dated March 1, 2011 between Seller and Buyer, and constitutes part of and is subject to the terms and provisions of such Master Agreement. Terms used but not defined herein shall have the meanings ascribed to them in the Master Agreement.

Standard of Review: All rates, terms and conditions as specified in this Confirmation hereunder shall remain in effect in accordance with their terms and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act. Absent the agreement of all parties to a proposed change, the standard of review for changes to any section of the Master Agreement or any Confirmation proposed by a party, a non-party, or the FERC acting sua sponte, shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra" doctrine).

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Agreement on their behalf as of the date first above written.

[redacted]	**Duke Energy Ohio, Inc.**
Name: [redacted]	Name:
Title: President	Title: President, Duke Energy Commercial Asset Management
Phone No: [redacted]	Phone No: 513.419.5467
Fax: [redacted]	Fax: 513.419.5914

Schedule 1

The Units shall consist of the following:

[redacted]

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2015/2016 RPM Base Residual Auction Results

2015/2016 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices resulting from the 2015/2016 RPM Base Residual Auction in comparison to those from 2007/2008 through 2014/2015 RPM Base Residual Auctions.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	RTO								
Auction Results	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012*	2012/2013	2013/2014**	2014/2015***	2015/2016
Resource Clearing Price	$40.80	$111.92	$102.04	$174.29	$110.00	$16.46	$27.73	$125.99	$136.00
Cleared UCAP (MW)	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2
Reserve Margin	19.2%	17.5%	17.8%	16.5%	18.1%	20.9%	20.2%	19.6%	20.2%

*2011/2012 BRA was conducted without Duquesne zone load.

**2013/2014 BRA includes ATSI zone load

***2014/2015 BRA includes Duke zone

****2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative

The cleared UCAP is the amount of unforced capacity that was procured in the auction to meet the RTO demand for capacity. The 2015/2016 Reliability Pricing Model (RPM) Base Residual Auction cleared 164,561.2 MW of unforced capacity in the RTO representing a 20.6% reserve margin. When the Fixed Resource Requirement (FRR) load and associated resources are considered the actual reserve margin for the entire RTO is 20.2%. The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in RPM and committed by FRR entities excess of the RTO load (including load served under the Fixed Resource Requirement alternative).

The 2015/2016 Base Residual Auction results reflect very strong participation by planned generation, demand resources and meaningful participation from energy efficiency resources.

New Generation Resource Participation

There was 8,207 MW ICAP of new generation resource participation, in the 2015/2016 Base Residual Auction including new generation and uprates at existing generating facilities. This figure is nearly 5 times greater than in the 2014/2015 Base Residual Auction value of 1,582.8 MW and more than double the previous high of 3,576.3 MW seen in the 2011/2012 Base Residual Auction which holds the distinction as the first Base Residual Auction held a full three years prior to the delivery year. Table 2A shows the

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2014/2015 RPM First Incremental Auction Results

Introduction

This document provides information for PJM stakeholders regarding the results of the 2014/2015 Reliability Pricing Model (RPM) First Incremental Auction. Incremental Auctions provide both a forum for capacity suppliers to purchase replacement capacity, and a means for PJM to adjust previously committed capacity levels due to reliability requirement increases or decreases combined with the appropriate share of the deferred Short-Term Resource Procurement Target.

The 2014/2015 First Incremental Auction opened on September 10, 2012 and the results were posted on September 21, 2012. This is the first Incremental Auction conducted with multiple Demand Resource (DR) products in effect (Annual DR, Extended Summer DR and Limited DR) as these additional DR products were implemented starting with the 2014/2015 Delivery Year. This document begins with a high level summary of the Incremental Auction results followed by sections containing detailed descriptions of the configuration and results of the 2014/2015 First Incremental Auction.

Summary of 2014/2015 RPM First Incremental Auction Results

Table 1 summarizes the clearing prices and cleared participant activity of the 2014/2015 First Incremental Auction. The First Incremental Auction cleared with unique prices in three regions of the RTO. In the PS-NORTH LDA, the resource clearing price for Limited, Extended Summer and Annual capacity was $399.62/MW-Day, $410.95/MW-Day and $410.95/MW-Day, respectively. In the MAAC region outside of the PS-NORTH LDA, which is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, Penelec, PEPCO, PPL, PSEG (outside of PS-NORTH LDA) and RECO Zones, the resource clearing price for Limited, Extended Summer and Annual capacity was $5.23/MW-Day, $16.56/MW-Day and $16.56/MW-Day, respectively. In the rest of the RTO, which is comprised of the AEP, APS, ATSI, ComEd, Dayton, DEOK, DOM, and Duquesne Zones, the resource clearing price for Limited, Extended Summer and Annual capacity was $0.03/MW-Day, $5.54/MW-Day and $5.54/MW-Day, respectively.

Across the entire RTO, total cleared participant buy bids (6,849.8 MW) exceeded total cleared participant sell offers (4239.8 MW) by 2,610 MW; participants procured a total net capacity amount of 2,610 MW of replacement capacity meaning that PJM effectively released 2,610 MW of previously procured capacity. Across the entire RTO, PJM effectively released 2,702.4 MW of previously procured Limited DR capacity and 87.6 MW of previously procured Extended Summer DR capacity and procured an additional 180 MW of capacity from Annual Resources.